Royalty Suspension Viability Program

RSVP

Documentation

United States Department of the Interior
Minerals Management Service
September 1, 1996

Preface

The Outer Continental Shelf (OCS) Deep Water Royalty Relief Act (DWRRA) directs the Secretary of the Interior to suspend royalties on existing leases in certain deep water areas of the Gulf of Mexico OCS Region when a specific set of conditions are met. Upon receipt of a complete application, the Secretary is to determine whether proposed new production would be economic while subject to the requirement to pay Federal royalties. The DWRRA directs the Secretary to consider in his determination, the increased risk of operating in deep water and all costs associated with exploring, developing and producing. Lessees are required to submit a complete application which provides the necessary raw and interpreted data on the field so that such a determination can be made.

There are two economic hurdles that a field must clear to be eligible for a royalty suspension. If, after reviewing the application, the Secretary determines that the new production would be economic while paying Federal royalties, then royalty obligations will not be suspended. Further, a determination that no amount of royalty-free production would make the new production economically viable also disqualifies the field from a royalty suspension. Alternatively, if the field would not be economic while paying Federal royalties but some amount of royalty-free production would make the new production economically viable, the field would qualify for at least the minimum suspension volume (MSV). Should production from a field not be economic with a royalty suspension volume equal to the mandated minimum, the Secretary must determine the precise volume of royalty-free production which would make the production economic.

A two-part evaluation process has been devised to direct royalty relief to fields that appear uneconomic with royalties but are potentially viable with royalty suspensions. The first part of the process is conducted by the royalty relief applicant and the second part is performed by the MMS.

Part 1: Applicants describe the risk of the proposed venture by specifying the uncertainty in the geologic, engineering, and cost inputs to the Royalty Suspension Viability Program (*RSVP*) as ranges of possible values and/or measures of the likelihood of occurrence for each possibility. These data are used in the *RSVP* to simulate the prospective net present value (PNPV) for the field. The *RSVP* is run in two stages. The Resource Module is run first to capture necessary resource parameters to be used as inputs into the Viability Module. This requires that the entire program be run twice with all distributed variable inputs in place for both simulations. The simulation of the PNPV does not include royalties or sunk costs. A positive PNPV indicates expected revenues exceed expected cost estimates when no royalty payments are made, or that the field appears to be profitable without royalties from a forward looking perspective. Therefore, if PNPV is positive, it can be said the field has been demonstrated to be **economically viable**. The *RSVP Documentation* provides more detailed explanation of how the discounted cash flow calculations are performed, how resources for the field are estimated, and how the PNPV is calculated.

Part 2: The MMS develops an independent assessment of the field in four steps.

1. It reviews the raw data submitted by the applicant, verifies that the model inputs accurately reflect these data and that the PNPV result derived from these data by *RSVP* is positive.

2. It compares the information submitted in the application to its own information. This is done to insure that the applicant's data include all of the field's resources, that the development plan is the most cost effective for extracting the resources, and that the cost estimates are in line with analogous projects. Where necessary, the MMS will adjust the applicant's data. If data adjustments are made, step one is repeated to confirm that PNPV is still positive. If the MMS determines that no amount of royalty-free production will make the field economically viable (PNPV is negative), then the applicant's request for royalty relief will be denied.

3. It incorporates royalty payments and eligible pre-application exploration and development expenditures reported by the applicant (sunk costs) and simulates the field's full net present value (FNPV) with a program called *RSVPP*. If sunk costs are critical, the past expenditures reported by the applicant may be audited. If FNPV is positive or zero, the field does not qualify for relief.

4. If the MMS calculates the FNPV to be negative using the *RSVPP* program, then it must find the volume of royalty free production (suspension volume) needed to make the PNPV = 0. If the computed suspension volume is equal to or less than the minimum mandated for the field's water depth category (17.5MMbbl >200 meters, 52.5MMbbl > 400 meters, and 87.5MMbbl > 800 meters), the applicant will receive the minimum suspension volume. If the computed amount exceeds the minimum suspension volume, the applicant will receive the computed amount.

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I. Introduction:

The Royalty Suspension Volume Program, or RSVP, is a LOTUS 1-2-3® spreadsheet model which employs the @RISK® risk analysis add-on software. The RSVP was developed by the Minerals Management Service (MMS) to be used by applicants who are applying to the MMS for a royalty suspension volume under the Deep Water Royalty Relief Act (DWRRA). An economic analysis performed by the applicant using the RSVP is a requirement of a complete application for certain eligible leases that were in existence prior to November 28, 1995 that wish to be considered for a royalty suspension volume under the DWRRA.

The RSVP is actually two models (or modules) in one. The *Resource Module* calculates the recoverable resources for the field while the *Viability Module* performs a discounted cash flow analysis of the revenues generated by the resources versus the costs of developing and producing the field.

Uncertainty in the information and data required for resource estimations and cash flow calculations is incorporated into the RSVP using the @RISK risk analysis software. Critical parameters are input as probability distributions of potential values for the parameter instead of single point or deterministic values. The program then performs a simulation consisting of many iterations (the terms iteration and trial are used interchangeably in this text). Every iteration is a separate calculation of the entire program where each input distribution is sampled and all calculations are performed using the sampled data. Distributions of possible results are created by saving the results of the calculations of each iteration. The average (mean) values of each output distribution are the expected values of the simulation.

The ultimate objective of the RSVP is to calculate a prospective net present value (PNPV) for the field. The PNPV is the discounted cash flow analysis for the field assuming no Federal royalties are paid and no sunk costs are considered. A positively valued PNPV indicates that some level of royalty suspension does exist that would allow the field to be economically viable using a specific discount rate. A field which cannot achieve a positively valued PNPV is an indication that complete relief of the burden of Federal royalties will not be enough savings to permit the field to become economically viable at a specific discount rate. Fields which cannot achieve a positive PNPV in the RSVP do not qualify for further consideration for a royalty suspension volume.

II. <u>Overview:</u>

A. The RSVP consists of 2 **modules**:

1. Resource Module, which is used in determining resource and product mix distributions for the Viability Module.
2. Viability Module, which is used to calculate the royalty free, prospective net present value (PNPV).
3. In the model RSVPP (a version of RSVP that is internal to the MMS) a third module (called the Economic Module) is used to calculate the full project net present value (FNPV) which includes all royalties and costs since discovery and calculates the suspension volume needed to make the PNPV >= 0.

B. An applicant qualifies for a volume suspension when **two tests** are passed:

1. Mean of the distribution of PNPV > 0, and
2. Mean of the distribution of FNPV < 0.
3. Pairing 2 versions of NPV estimates fulfills two objectives:
    a. Considers all eligible costs since discovery in judging whether a field is not economic absent relief, as mandated in the Legislation and included the Interim rule.
    b. Insures that the field is economically viable with royalty relief.

C. **Computer software requirements**:

1. The program was developed with LOTUS 1-2-3 version 2.4 and the @RISK add-on for LOTUS 1-2-3 version 2.0. Both 1-2-3 and @RISK must reside in the same directory.
2. The following instructions for using RSVP presume the user has basic familiarity with the LOTUS 1-2-3 and @RISK programs. For quick-reference procedures on running the program refer to;
   a. II, D pg. 13 for the Resource Module.
   b. III, D pg. 46 for the Viability Module.
3. The RSVP has been thoroughly tested using LOTUS 1-2-3 version 2.4 and @RISK version 2.0. Problems with @RISK when running simulations with more than 250 iterations were encountered using LOTUS 1-2-3 version 2.2. The model has not been tested in LOTUS 1-2-3 and @RISK for Windows. Although, in theory, the model should work in using Windows based software, the MMS does not recommend using them until it can be thoroughly tested. Although 1-2-3 spreadsheets are translatable into EXCEL®, and @RISK makes an EXCEL version, the special @RISK functions used in models programmed with @RISK for 1-2-3 do not translate into @RISK for EXCEL. Therefore, EXCEL cannot be used to run this model. For the future, Windows and compiled/stand-alone versions of RSVP are being developed.

D. **Special features** have been added to the otherwise conventional cash flow analysis performed by the program.

1. Simulation using Latin Hypercube sampling from distributions as a means of considering the risks and uncertainties associated with deep water development.

a. To account for the uncertainty they identify into the analysis, applicants specify a range of possible values and/or some measure of the likelihood of occurrence for each possibility as inputs for each of dozens of geologic and cost variables.

b. For each simulation, 1,000 iterations are required so that the large number of input distributions can be adequately sampled and a sufficient distribution of the possible states-of-nature can be modeled.

c. A random number seed (specified by MMS) is used to insure that the same reproducible trials are used in both qualification tests.

2. Two-stage sampling to approximate sequential decision-making.

a. The 2 decision stages are:

(1) the decision to apply for royalty relief for a field, then

(2) the decision to commit large development investments on the field.

b. The first decision stage is simulated by the resource module. Resources estimated on each trial by this module dictate design and cost characteristics of the production platform and facilities.

c. The second decision stage is simulated by the viability module. Reserves estimated on each trial by this module dictate the number of development wells, the production profile, and the ultimate recovery.

d. The sampling of resources in the resource module is a simulation of the decision made to proceed with the level of information available before the final "go or no-go" development decision has been made.

e. The sampling of reserves in the viability module is a simulation of the final "go or no-go" decision to develop.

3. Economic limit rules to restrict cash flow calculations and sampling combinations to ones that represent logical actions by applicants.

a. Production and operating expenses are automatically curtailed after the last year that revenues exceed operating expenses.

b. Trials where revenues are less than operating cost every year are eliminated from the simulation.

E. **Program layout:**

1. The *R S V P Template Schematic* on page 6, is a map of the program which shows where to find the input, computation, and output spreadsheet cell locations for the Resource, Viability, and Economic Modules. The version of RSVP which is available to applicants does not contain the Economic Module and, therefore, performs no calculations beyond column FE of the spreadsheet.

2. The figure, < < < *R S V P* > > > on page 7, depicts the applicant identification portion of the spreadsheet that leads off the program. All inputs to this screen are alpha inputs except the *Field Water Depth* and *Lease Royalty Rate* which must be numerical inputs.

III. <u>Resource Module:</u>

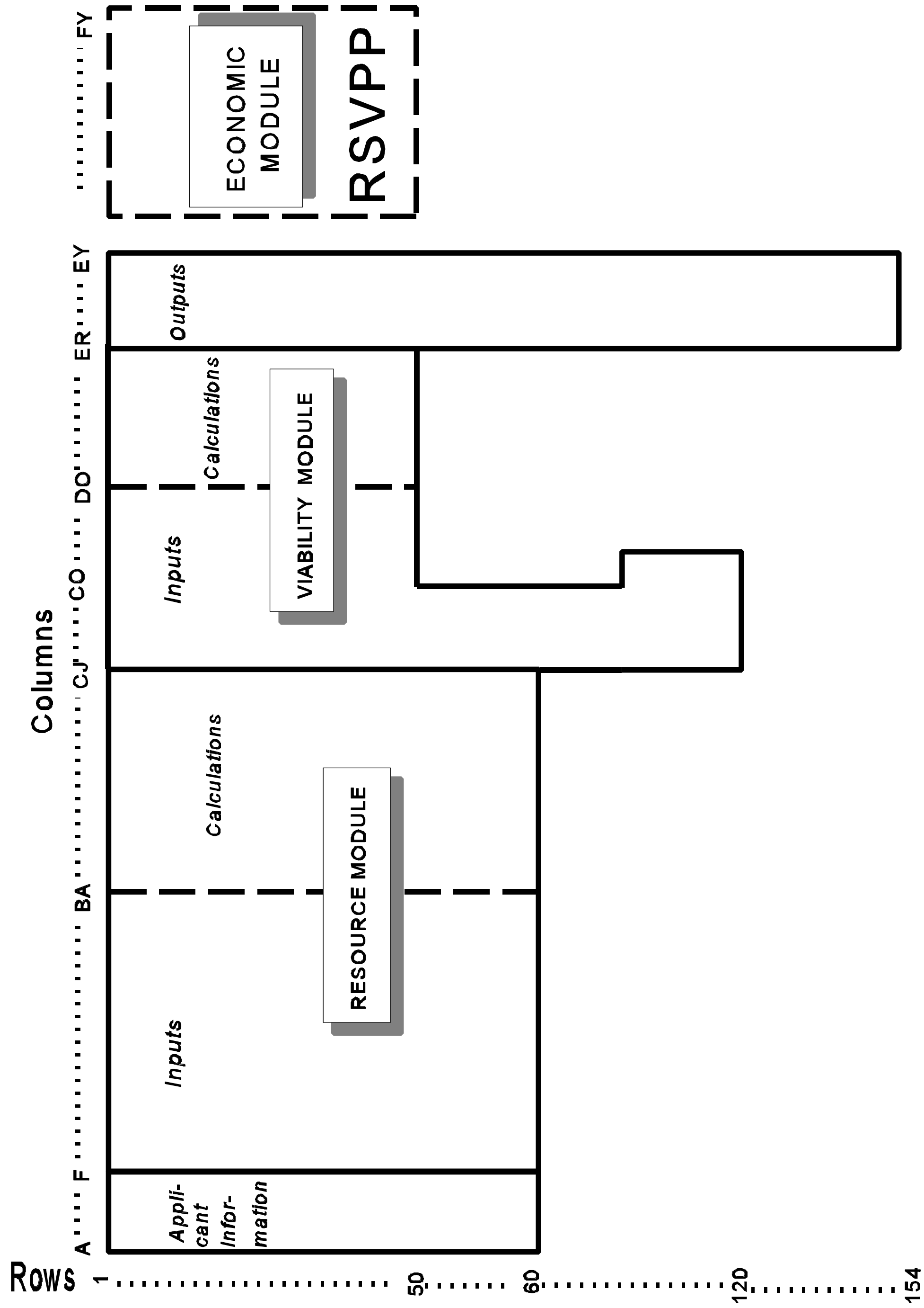
A. **Objectives:**

1. Calculate probability distribution parameters implied by the detailed geologic and engineering data elements from all of the potential reservoirs of the field.

2. Sample the distribution of resources for the field on each iteration of the Viability Module simulation.

3. Because of the sequential decision making feature of RSVP, the program must be run twice before a value of PNPV can be obtained. The program is initially run so this module can estimate key characteristics of the distributions of resources and oil fraction to be used as inputs in the Viability Module. The Resource Module also serves as a subroutine of the Viability Module to calculate resources during each iteration to be used in

R S V P Template Schematic



```
A  B          C                            D      E    F

 |           * * * * * * * * * * * * * * * * * * * * * * *          ||
 |           *                                           *          ||
 |           *           < < <  R S V P  > > >           *          ||-
 |           *                                           *          ||
 |           *    Royalty Suspension Viability Program   *          ||
 |           *                                           *          ||
 |           * * * * * * * * * * * * * * * * * * * * * * *          ||
 |                                                                  ||
 |          Field Name:                  Buffalo                    ||
 |                                                                  ||
 |  Field Water Depth (meters):                          745        ||
 |                                                                  ||
 |      Date of Application:            June 1, 1996                ||
 |                                                                  ||
 |    Name of Company Applying:  Richalo Exploration Company        ||
 |                                                                  ||
 |       Applicant Contact:            Richard Winnor               ||
 |                                                                  ||
 |    Contact Telephone Number:        (703) 787-1533               ||
 |                                                                  ||
 |                                                                  ||
 | Lease Data:                                                Lease ||
 |                                                          Royalty||
 |     Leases Comprising Field         Lease Ownership        Rate  ||
 |    ------------------------- ----------------------------- -------||
 |  1)                                                              ||
 |  2)                                                              ||
 |  3)                                                              ||
 |  4)                                                              ||
 |  5)                                                              ||
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 | 31)                                                              ||
 | 32)                                                              ||
 | 33)                                                              ||
 | 34)                                                              ||
 | 35)                                                              ||
 |                                                                  ||
```

selecting a production capacity and capital expenditure profile scenario for the cash flow analysis. The theory and procedures for this approach are explained in detail in later portions of this documentation.

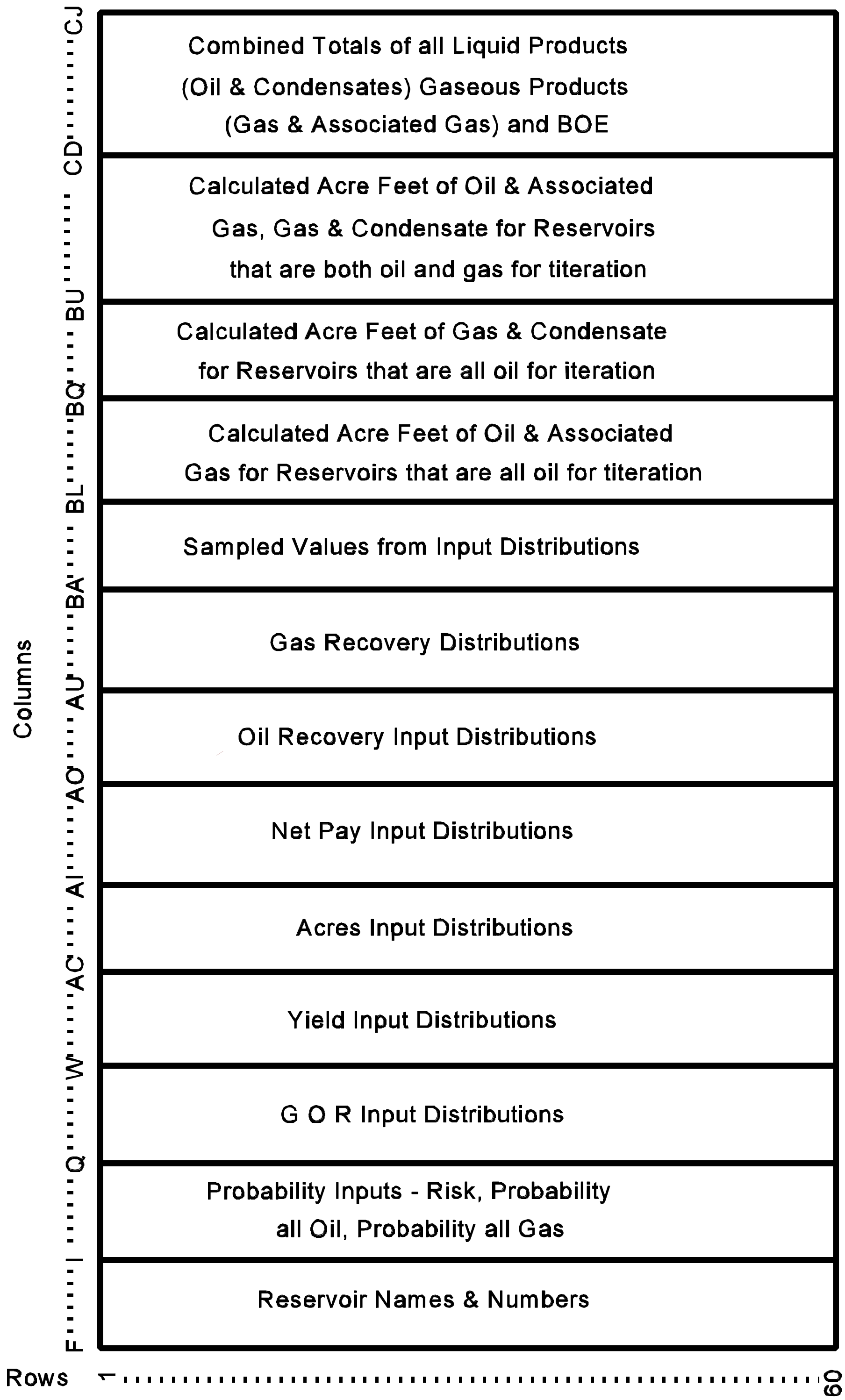
B. **Inputs:** The figure, *Resource Module Schematic*, on page 9 is a map of the module which shows where to find the input and computation spreadsheet cell locations. The figures on pages 20 through 31 are reproductions of the actual screen displays during an example program simulation. The figures illustrate the configuration, inputs, and results of this module.

Note: In this and any program examples, the input data and calculated results are purely hypothetical and are strictly for illustrative purposes and, therefore, are not derived from nor representative of any specific Outer Continental Shelf field.

1. The program can handle up to 50 reservoirs (15 are used in the example). [cells G7 ... H56] In this area of the spreadsheet the user identifies all of the potential reservoirs that may contribute to the field. The *Reservoir Name* is an alpha input and is strictly for identification purposes. The *Reservoir Number* can either be alpha or numeric and is a more condensed identifier that is carried throughout each screen of the Resource Module for convenience. Once all reservoir numbers have been entered, calculate the spreadsheet by striking the "F9" key. This places the reservoir numbers in each screen.

2. Each reservoir must be given a probability that it may be dry or that for some reason it may not produce. The input must be expressed as a decimal fraction with a value of 0 indicating that the reservoir will always produce and a value of 1 indicating that the reservoir will never produce. The program also has the feature of being able to declare dependencies between reservoirs for these probabilities. These inputs occur in spreadsheet cells K7..M56. Example inputs are illustrated on the corresponding screen display reproduction page of this text. Each

Resource Module Schematic



reservoir must be given an *Independent or Dependent Variable Name* regardless of whether dependencies are going to be used. We have found it useful to simply copy the reservoir name here, although any alphanumeric code may be used. If all reservoirs are to be independent then each reservoir must have a unique independent variable name. If a dependency is desired, the dependent variable must have the exact same variable name as the independent variable. Further, the dependent variable must have a *Rank Order Coefficient* between -1 and 1. The coefficient is an expression of the degree of dependency and can range form a value of 1 (indicating direct dependency) to value of -1 (indicating in inverse direct dependency).

3. Each reservoir must also be assigned a probability that it may be all oil and a probability that it may be all gas in spreadsheet cells O7..P56. These inputs must also be expressed as decimal fraction with a values between 0 and 1. Further, the sum of these two probabilities cannot sum to greater than 1. An input value of 1 for a reservoir's *Probability Reservoir is All Oil* indicates that oil will always be the dominant product from that reservoir. Such an input must always be offset with an input value of 0 for the reservoir's corresponding *Probability Reservoir is All Gas*. When probability values of less than 1(or greater than 0) are used, and the two probability values sum precisely to 1, then the reservoir can either have oil or gas as the dominant product. When the two probability values sum to less than 1 then oil, gas, or both oil and gas can be dominant products for the reservoir. By using the term "dominant product" we do not mean that will be the only product that will be produced from that reservoir. Rather, the dominant product (whether it be oil or gas) simply directs the program to use the gas/oil ratio (GOR) to calculate associated gas production when oil is dominant or to use the yield to calculate condensate production when gas is the

dominant product. The process the program uses for sampling whether a reservoir will be oil dominant, gas dominant, or both for each iteration is explained later in this text.

4. Estimates of the gas/oil ratio (GOR), condensate yield, reservoir acreage, average reservoir net pay, oil recovery from the reservoir, and gas recovery from the reservoir are the remaining input requirements for the Resource Module of the RSVP. Each of these variables are input into the program in the same manner. The inputs are located in cells S7..AZ56 of the spreadsheet. Each variable may be input either as a triangular distribution, a lognormal distribution, or as a single point deterministic value. If there exists uncertainty about what precise value may exist for an input variable then one of the distributed input options should be used. If the value of an input variable is known with certainty, perhaps a single point estimate will be chosen.
    a. Triangular distributions are specified with minimum, most likely, and maximum values.
    b. Lognormal distributions can be specified with either a mean and standard deviation; or with mean, 1 percentile, and 99 percentile values.
    c. To input a variable as a single point value, choose a triangular distribution then give the minimum, most likely, and maximum inputs all the same values.

    It is imperative to input the *Distribution Type* for each reservoir. These inputs must read either *Triangular* or *Lognormal* precisely for the program to function properly. In the event that a reservoir is to be always oil dominant or always gas dominant (as evidenced by a value of 1 for the *Probability Reservoir Is All Oil* or for the *Probability Reservoir Is All Gas*) then input values for the GOR or Yield and Oil Recovery or Gas Recovery are not necessary for the non-dominant product. For example, if oil is always to be the dominant product for the reservoir then input values for Yield and Gas Recovery are not necessary. Conversely, if gas is always to be the dominant product then input values for GOR and Oil Recovery are not necessary. Even though input values are not necessary in these cases, the program does require that *Triangular* be inserted as the *Distribution Type* for the reservoir and the reservoir's corresponding *Likely Value*, *Minimum Value,* and *Maximum Value* input cells be left blank.

C. **Calculations:**

1. On each iteration, the program:

a. Predicts whether reservoir is dry by sampling at random a value between 0 and 1(*RISK* cells BC7..BC56), if the random sample is less than or equal to the *Probability Reservoir Is Dry* for the reservoir, a value of 0 is assigned and the reservoir will not produce during this iteration. If the random sample is greater than the *Probability Reservoir Is Dry*, a value of 1 is assigned and the reservoir will produce during this iteration. For an explanation of how @RISK handles dependencies refer to the @RISK text, particularly pages 5-107 through 5-109.

b. Predicts whether oil, gas, or both oil and gas will be the dominant products produced by the reservoir. Again a value is sampled at random between 0 and 1 (*PROB/PROG* cells BD7..BD56). If the sampled value is less than the *Probability Reservoir Is All Oil* for the reservoir, the reservoir is oil dominant for this iteration. If the sampled value is greater than 1 *minus* the *Probability Reservoir Is All Gas* the reservoir is gas dominant for this iteration. If the sampled value is greater than or equal to the *Probability Reservoir Is All Oil* and less than or equal to the *Probability Reservoir Is All Gas* then the reservoir has both oil and gas as dominant products for the iteration. To determine the proportion of the reservoir which is oil dominant and the proportion of the reservoir which is gas dominant, a value is sampled at random between .01 and .99 (*PROP* cells BE7..BE56), this value represents the oil dominant portion of the oil and gas reservoir. The gas portion is 1 *minus* this sampled value.

c. Samples from *GOR*, *Yield*, *ACRES*, *NET PAY*, *OIL RECOVERY,* and *GAS RECOVERY* input distributions [cells BF7 ... BK56].

d. Computes acres, acre feet, oil, associated gas, gas, condensate, and BOE's for each reservoir that produces during the iteration. [cells BN7 ... CI56]

e. Calculates the field results for the iteration by summing the above results across all reservoirs. [cells BN58 ... CI58]

2. For each simulation, the program:

a. Repeats above calculations over 1000 iterations to result in distributions of each parameter for each reservoir and for the field.

b. Tracks distributions of results for the following calculated field values:

(1) Acres

(2) Acre Feet

(3) Oil Recovery

(4) Gas Recovery

(5) Geologic Probability of producing No Hydrocarbons

(6) Oil produced from all Oil Reservoirs

(7) Associated Gas produced from all Oil Reservoirs

(8) Gas produced from all Gas Reservoirs

(9) Condensate produced from all Gas Reservoirs

(10) Oil produced from all Oil & Gas Reservoirs

(11) Associated Gas produced from all Oil & Gas Reservoirs

(12) Gas produced from all Oil & Gas Reservoirs

(13) Condensate produced from all Oil & Gas Reservoirs

(14) Total Oil (oil & condensate) for all Reservoirs

(15) Total Gas (gas and associated gas) for all Reservoirs

(16) Total BOE's for all Reservoirs

(17) Oil Fraction of all Reservoirs

The mean, standard deviation, minimum, median, and maximum values of these field distributions can be saved into the spreadsheet later in cells ER20 ... EX79. Instructions on how to do this appear later in this text.

D. **Procedure:**

1. After data input, a simulation of the program involves the following steps:

Note: The @RISK software used to program and execute the RSVP has several features which must be abided so that reproducible results will occur. The @RISK software begins its execution of a simulation by sampling the precise number of random numbers needed for the simulation and, if dependencies are requested, ranking and sorting the random numbers. How many random numbers are needed depends directly on the number of input distributions specified for use in the program. If a simulation should be made with only input data in place for the Resource Module, less random numbers will be needed than if a simulation was made with input data in place for both the Resource and Viability Modules. If this were the case, each simulation would be using different random numbers for the same calculations and different results will occur. It is very important, therefore, that all input data for both the Resource Module and the Viability Module be in place in the *program prior to the running of simulations from which results must be gleaned.*

a. Calculate the spreadsheet [key F9], then invoke @RISK [probably Alt and F8], set the Settings, Sampling to Latin Hypercube; the Settings, Generator to the current seed value specified by the MMS; and the Iterations, Iterations to 1000; then Execute.

b. When the simulation is complete, invoke RISKGraph [Results, Current] & inspect the results.

c. If the entire field is sampled as being dry during one or more iterations (i.e., output distribution *E - Dry Risk* >0), @RISK filtering must be used to calculate conditional values for the two key distributions described in III, D., 1., d. below. Filtering removes values from these distributions that occur during iterations where the entire field is sampled as being dry.

(1) This adjustment removes a distortion from the Resource Module's *P - Total BOE* and *S - Oil Frac.* output distributions. The Resource Module in the initial simulation run develops distributions of resources and of oil fraction that include zero values from iterations where the field was sampled as being dry. Removing these zero values from the distributions by "filtering" results produces distributions which represent the condition when hydrocarbons are present.

(2) The @RISK procedure for filtering is as follows:

(a) From @RISKGraph (Alt and F8), invoke Zoom/Rescale, Global, Configure, Filter.

(b) Enter the filter condition ">0" and select Go.

d. Certain statistics from the *P - Total BOE* distribution and the *S - Oil Frac. 1* distribution are input requirements for the Viability Module of the program. The mean, standard deviation, minimum value, and maximum value of these distributions should be recorded (written down) by the user so that they can be reproduced in the appropriate spreadsheet location as inputs into the Viability Module.

e. A default set of outputs that have been tailored to the focus of the Viability Module is included in the template.

   (1) See page 64 of this text for a list of these outputs and the spreadsheet cell location addresses from which they are collected.

   (2) If some or all of these default outputs are deleted [invoke @ RISK and use commands Outputs, Delete], alternative results from a simulation can be chosen. A maximum of 32 can be selected for any one simulation.

f. The table on the following page titled *EXAMPLE ALTERNATIVE FORMAT RESULTS FOR RESOURCE MODULE* illustrates an alternative set of Outputs for a single reservoir that have been tailored to the Resource Module. It can be created as follows:

   (1) After deleting names and ranges of the default outputs, define names and ranges for the alternative outputs [@ RISK commands Outputs, Select], Execute the simulation.

(2) When the simulation is complete, invoke RISKGraph [Results, Current] and create a Statistics report as follows;

  (a) Use commands Reports, Statistics, Format to list available statistics.

EXAMPLE ALTERNATIVE FORMAT RESULTS FOR RESOURCE MODULE

Reservoir #1

Sampling type: Latin Hypercube   Number of simulations: 1
Number of iterations: 1000   Seed value: 104

Output ranges:	Cell Address	Simulation Mean	Conditional Mean	Standard Deviation	Minimum	Median	Maximum
A - #1 GOR (SCF/STB)	BF7	1.690		0.082	1.404	1.688	1.970
B - #1 YIELD (bbl/MMcf)	BG7	0.139		0.019	0.078	0.138	0.211
C - #1 ACRES	BH7	242		26	161	240	338
D - #1 NET PAY (feet)	BI7	121		7	100	121	151
E - #1 O RECOV (Mbbl/AC-ft)	BJ7	0.117		0.091	0.007	0.092	0.956
F - #1 G RECOV (MMcf/AC-ft)	BK7	0.492		0.443	0.031	0.363	4.641
G - #1 OIL (Mbbl)	CG7	2,028	3,514	2,250	0	1,526	15,650
H - #1 GAS (MMcf)	CH7	6,337	10,982	10,230	0	3,023	143,437
I - #1 BOE (MBOE)	CI7	3,155	5,469	3,646	0	2,161	29,205
J - #1 RISK	BC7	0.577	1.000	0.494	0	1	1
K - #1 OIL/OIL (Mbbl)	BO7	592	1,026	1,650	0	0	15,650
L - #1 OIL/GAS (MMcf)	BP7	1,006	1,743	2,824	0	0	28,066
M - #1 GAS/GAS (MMcf)	BS7	3,912	6,779	9,981	0	0	143,437
N - #1 GAS/OIL (Mbbl)	BT7	1,034	1,791	1,810	0	0	6,955
O - #1 BOTH/OIL (Mbbl)	BX7	262	454	1,030	0	0	14,178
P- #1 BOTH/AGAS (MMcf)	BY7	441	764	1,727	0	0	21,966
Q - #1 BOTH/GAS (MMcf)	CB7	979	1,696	3,542	0	0	51,079
R- #1 BOTH/COND (Mbbl)	CC7	140	243	510	0	0	5,719

(b) Toggle off everything but;

i) Expected value.

ii) Minimum value.

iii) Maximum value.

iv) Standard deviation.

v) Simulation.

vi) 50% percentile (median value).

(c) Touch Escape to exit and Update to save this report format.

(3) Export the Statistics for the result to the spreadsheet as follows;

(a) Save a Statistics report with the @RISK commands [Reports, Statistics, All] and give the .RST a filename.

(b) Exit @RISKGraph (saving a .REV file is optional) and move to a blank area of the RSVP spreadsheet or to a separate spreadsheet.

(c) Invoke @RISK [Alt and F8], copy the simulation parameters into this spreadsheet [@RISK Settings, Parameters, Spreadsheet], and in another blank area import the .RST file with the command [Results, Report] and the filename assigned in (1) above.

(4) Calculate the conditional means (mean of trials where hydrocarbons are present) for the oil and gas quantities by;

(a) Inserting a row for conditional mean in the @RISK Simulation Statistics table in the spreadsheet.

(b) Compute the conditional means by dividing each simulation mean by the expected value/mean of the Risk distribution [e.g., value from spreadsheet cell BC7].

(5) Range, Transpose the Statistics table and line it up with the corresponding rows of the Simulation Parameter table and Format.

(6) Extracting these results is not necessary for any application report, but the option is raised if more intensive examination of Reserve module results is desired.

```
     F                             G                                H     I
  1 ||            * * *  R E S O U R C E   M O D U L E  * * *             |
  2 ||                                                                    |
  3 ||------------------------- Reservoir Inputs: ------------------------|
  4 ||                                                          Reservoir |
  5 ||                    Reservoir Name                          Number  |
  6 || ------------------------------------------------------- -----------|
  7 ||                      Reservoir 1                                1 |
  8 ||                      Reservoir 2                                2 |
  9 ||                      Reservoir 3                                3 |
 10 ||                      Reservoir 4                                4 |
 11 ||                      Reservoir 5                                5 |
 12 ||                      Reservoir 6                                6 |
 13 ||                      Reservoir 7                                7 |
 14 ||                      Reservoir 8                                8 |
 15 ||                      Reservoir 9                                9 |
 16 ||                      Reservoir 10                              10 |
 17 ||                      Reservoir 11                              11 |
 18 ||                      Reservoir 12                              12 |
 19 ||                      Reservoir 13                              13 |
 20 ||                      Reservoir 14                              14 |
 21 ||                      Reservoir 15                              15 |
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   I J       K           L             M     N      O          P       Q
 1 |----------------------- Probability Inputs -------------------------|-
 2 | R                                       |   (Must Add to <= 1)     |
 3 | S  Probability  Independent   (>=-1,<=1) | Probability Probability  |
 4 | V   Reservoir   or Dependent  Rank Order |  Reservoir   Reservoir   |
```

#	Is Dry	Variable Name	Coefficient	Is All Oil	Is All Gas
1	0.42	Reservoir 1		0.33	0.42
2	0.42	Reservoir 1	0.85	0.93	0.07
3	0.31	Reservoir 3		0.13	0.62
4	0.92	Reservoir 4		0.18	0.57
5	0.15	Reservoir 5		0.68	0.20
6	0.64	Reservoir 6		0.26	0.49
7	0.25	Reservoir 7		0.73	0.14
8	0.37	Reservoir 7	-0.87	0.57	0.30
9	0.13	Reservoir 9		0.88	0.07
10	0.70	Reservoir 10		0.16	0.59
11	0.03	Reservoir 11		0.52	0.35
12	0.27	Reservoir 11	0.53	0.20	0.55
13	0.20	Reservoir 11	0.87	0.92	0.08
14	0.29	Reservoir 11	0.73	0.79	0.16
15	0.08	Reservoir 11	0.62	0.84	0.11

Q R S T U V W

GOR (SCF/STB)

RSV #	Distribution Type	If Lognormal> Mean Value / or If Lognormal Mean Value / If Triangular> Likely Value	Std. Deviation / 1st Percentile / Minimum Value	*Leave BLANK!* / 99th Percentile / Maximum Value
1	Lognormal	1,691	1,438	1,818
2	Lognormal	706	687	797
3	Lognormal	540	282	

Row	#	Distribution Type	Z	AA	AB
10	4	Lognormal	1,623	1,467	
11	5	Lognormal	1,811	1,654	1,830
12	6	Lognormal	1,074	614	
13	7	Lognormal	816	711	1,372
14	8	Lognormal	1,407	1,306	1,568
15	9	Lognormal	1,331	420	1,580
16	10	Lognormal	1,459	1,244	
17	11	Lognormal	1,559	931	
18	12	Lognormal	1,608	1,535	
19	13	Lognormal	765	400	1,558
20	14	Lognormal	817	759	
21	15	Triangular	278	259	913

Yield (bbl/MMcf)

W	X	Y	Z	AA	AB
	RSV #	Distribution Type: If Lognormal> / or If Lognormal / If Triangular>	Mean Value / Mean Value / Likely Value	Std. Deviation / 1st Percentile / Minimum Value	*Leave BLANK!* / 99th Percentile / Maximum Value
7	1	Lognormal	139	61	148
8	2	Triangular	40	30	65
9	3	Triangular	95	80	154
10	4	Lognormal	77	67	110
11	5	Lognormal	135	71	169
12	6	Lognormal	71	42	
13	7	Lognormal	44	33	
14	8	Triangular	103	38	123

15	9	Triangular	41	27	129
16	10	Lognormal	81	30	
17	11	Lognormal	113	32	153
18	12	Lognormal	38	25	
19	13	Triangular	146	126	150
20	14	Triangular	89	70	122
21	15	Lognormal	84	35	
22					
23					
24					
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	AC	AD	AE	AF	AG	AH	AI
1				ACRES			
2		R	Distribution Type				
3		S	If Lognormal>	Mean Value	Std. Deviation	*Leave BLANK!*	
4		V	or If Lognormal	Mean Value	1st Percentile	99th Percentile	
5		#	If Triangular>	Likely Value	Minimum Value	Maximum Value	
6							
7		1	Lognormal	242	178	301	
8		2	Triangular	246	214	359	
9		3	Lognormal	298	89	328	
10		4	Triangular	118	91	133	
11		5	Lognormal	225	171	294	
12		6	Triangular	351	242	356	
13		7	Lognormal	83	65	385	
14		8	Triangular	288	60	338	
15		9	Lognormal	356	344	399	
16		10	Lognormal	317	304		
17		11	Lognormal	326	283	328	
18		12	Lognormal	220	218	352	
19		13	Lognormal	231	197		

14	Triangular	123	100	199
15	Lognormal	123	92	254

AJ	AK	AL	AM	AN
NET PAY (feet)				
R S V #	Distribution Type If Lognormal> or If Lognormal If Triangular>	 Mean Value Mean Value Likely Value	 Std. Deviation 1st Percentile Minimum Value	 *Leave BLANK!* 99th Percentile Maximum Value
1	Lognormal	120.8	92.1	126.8
2	Lognormal	71.2	52.2	
3	Triangular	47.7	35.6	57.2
4	Triangular	80.4	49.3	116.7
5	Lognormal	79.0	67.8	
6	Lognormal	68.8	60.9	
7	Triangular	65.3	18.3	78.4
8	Lognormal	62.3	43.3	108.3
9	Lognormal	100.1	27.2	
10	Lognormal	67.0	20.0	88.0
11	Lognormal	64.0	23.3	110.3
12	Triangular	36.5	31.2	48.6
13	Triangular	74.5	35.3	80.2
14	Triangular	82.9	16.7	107.7
15	Lognormal	75.2	49.9	

OIL RECOVERY (bbl/Ac-Ft)

	AO	AP	AQ	AR	AS	AT	AU
2		R	Distribution Type				
3		S	If Lognormal>	Mean Value	Std. Deviation	*Leave BLANK!*	
4		V	or If Lognormal	Mean Value	1st Percentile	99th Percentile	
5		#	If Triangular>	Likely Value	Minimum Value	Maximum Value	
7		1	Lognormal	117	91		
8		2	Triangular	261	253	443	
9		3	Triangular	282	265	364	
10		4	Lognormal	200	119	326	
11		5	Lognormal	364	344	492	
12		6	Lognormal	391	140	403	
13		7	Triangular	363	317	577	
14		8	Lognormal	463	298	563	
15		9	Triangular	515	191	554	
16		10	Lognormal	461	243	515	
17		11	Lognormal	225	171	340	
18		12	Triangular	250	213	254	
19		13	Lognormal	419	135		
20		14	Triangular	318	119	417	
21		15	Triangular	494	138	540	

GAS RECOVERY (mcf/Ac-Ft)

R S V #	Distribution Type If Lognormal> or If Lognormal If Triangular>	Mean Value Mean Value Likely Value	Std. Deviation 1st Percentile Minimum Value	*Leave BLANK!* 99th Percentile Maximum Value
1	Lognormal	493	451	
2	Lognormal	1,151	623	
3	Lognormal	985	629	
4	Lognormal	1,148	671	1,400
5	Lognormal	651	524	1,359
6	Lognormal	847	792	
7	Lognormal	635	589	1,015
8	Triangular	808	608	1,171
9	Lognormal	708	660	
10	Lognormal	861	824	991
11	Lognormal	1,296	769	
12	Lognormal	1,293	444	
13	Lognormal	1,150	472	1,261
14	Triangular	997	658	1,181
15	Triangular	815	594	1,110

Sampled Values for Trial

RSV #	RISK	PROB/ PROG	PROP	GOR	Yield	ACRES	NET PAY	Oil Recovery (Mbbl/AF)	Gas Recovery (MMcf/AF)
1	1	1	1	1.691	0.139	242	120.8	0.1166	0.4928
2	1	1	1	0.706	0.045	273	71.2	0.3190	1.1511
3	1	1	1	0.540	0.110	298	46.8	0.3038	0.9848
4	0	1	1	1.623	0.077	114	82.1	0.1998	1.1476
5	1	1	1	1.811	0.135	225	79.0	0.3639	0.6512
6	0	1	1	1.074	0.071	316	68.8	0.3909	0.8470
7	1	1	1	0.816	0.044	83	54.0	0.4189	0.6349
8	1	1	1	1.407	0.088	229	62.3	0.4628	0.8622
9	1	1	1	1.331	0.066	356	100.1	0.4200	0.7078
10	0	1	1	1.459	0.081	317	67.0	0.4612	0.8607
11	1	1	1	1.559	0.113	326	64.0	0.2248	1.2957
12	1	1	1	1.608	0.038	220	38.8	0.2390	1.2932
13	1	1	1	0.765	0.141	231	63.3	0.4194	1.1498
14	1	1	1	0.817	0.094	141	69.1	0.2846	0.9454
15	1	1	1	0.483	0.084	123	75.2	0.3904	0.8394
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000

40	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
41	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
42	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
43	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
44	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
45	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
46	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
47	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
48	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
49	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
50	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
51	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
52	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
53	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
54	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
55	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
56	0	0	1	1	0.000	0.000	0	0.0	0.0000	0.0000
57										
58										
59										
60										

Resource Module Calculations:

	BL BM	BN	BO	BP	BR	BS	BT
2	R	--------- Oil Result		------	--------- Gas Result		-------
3	S			Associated			
4	V		Oil	Gas		Gas	Condensate
5	#	Acre Feet	(Mbbl)	(MMcf)	Acre Feet	(MMcf)	(Mbbl)
7	1	0	0	0	0	0	0
8	2	19,431	6,198	4,378	0	0	0
9	3	0	0	0	13,952	13,740	1,512
10	4	0	0	0	0	0	0
11	5	17,738	6,454	11,691	0	0	0
12	6	0	0	0	0	0	0
13	7	4,462	1,869	1,525	0	0	0
14	8	14,256	6,598	9,284	0	0	0
15	9	35,595	14,949	19,892	0	0	0
16	10	0	0	0	0	0	0
17	11	20,871	4,692	7,314	0	0	0
18	12	0	0	0	8,516	11,013	415
19	13	14,645	6,142	4,700	0	0	0
20	14	9,742	2,772	2,266	0	0	0
21	15	9,271	3,620	1,749	0	0	0
22	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0
26	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0
29	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0
32	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0
34	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0
37	0	0	0	0	0	0	0
38	0	0	0	0	0	0	0
39	0	0	0	0	0	0	0
40	0	0	0	0	0	0	0
41	0	0	0	0	0	0	0
42	0	0	0	0	0	0	0
43	0	0	0	0	0	0	0
44	0	0	0	0	0	0	0

45	0	0	0	0	0	0	0
46	0	0	0	0	0	0	0
47	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0
49	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0
51	0	0	0	0	0	0	0
52	0	0	0	0	0	0	0
53	0	0	0	0	0	0	0
54	0	0	0	0	0	0	0
55	0	0	0	0	0	0	0
56	0	0	0	0	0	0	0
57							
58		146,011	53,296	62,800	22,468	24,753	1,927
59							
60			Oil Result			Gas Result	
61			1			1	

	BU BV	BW	BX	BY	B CA	CB	CC CD
1							
2	R	Oil and Gas Result					
3	S			Associated			
4	V		Oil	Gas		Gas	Condensate
5	#	Acre Feet	(Mbbl)	(MMcf)	Acre Feet	(MMcf)	(Mbbl)
6							
7	1	14,597	1,701	2,876	14,597	7,193	1,003
8	2	0	0	0	0	0	0
9	3	0	0	0	0	0	0
10	4	0	0	0	0	0	0
11	5	0	0	0	0	0	0
12	6	0	0	0	0	0	0
13	7	0	0	0	0	0	0
14	8	0	0	0	0	0	0
15	9	0	0	0	0	0	0
16	10	0	0	0	0	0	0
17	11	0	0	0	0	0	0
18	12	0	0	0	0	0	0
19	13	0	0	0	0	0	0
20	14	0	0	0	0	0	0
21	15	0	0	0	0	0	0
22	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0
26	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0
29	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0
32	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0
34	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0
37	0	0	0	0	0	0	0
38	0	0	0	0	0	0	0
39	0	0	0	0	0	0	0
40	0	0	0	0	0	0	0
41	0	0	0	0	0	0	0
42	0	0	0	0	0	0	0
43	0	0	0	0	0	0	0
44	0	0	0	0	0	0	0
45	0	0	0	0	0	0	0
46	0	0	0	0	0	0	0
47	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0

49	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0
51	0	0	0	0	0	0	0
52	0	0	0	0	0	0	0
53	0	0	0	0	0	0	0
54	0	0	0	0	0	0	0
55	0	0	0	0	0	0	0
56	0	0	0	0	0	0	0
57							
58		14,597	1,701	2,876	14,597	7,193	1,003
59							
60			Oil & Gas Result				
61			1				

CD	CE	CF	CG	CH	CI	CJ
1						
2	Combined Totals					
3						-
4	Reservoir		Oil	Gas	BOE	
5	Number	ACRES	(Mbbl)	(MMcf)	(MBOE)	
6						
7	1	242	2,704	10,069	4,496	
8	2	273	6,198	4,378	6,977	
9	3	298	1,512	13,740	3,956	-
10	4	0	0	0	0	
11	5	225	6,454	11,691	8,535	
12	6	0	0	0	0	
13	7	83	1,869	1,525	2,140	
14	8	229	6,598	9,284	8,250	
15	9	356	14,949	19,892	18,489	
16	10	0	0	0	0	
17	11	326	4,692	7,314	5,994	
18	12	220	415	11,013	2,375	
19	13	231	6,142	4,700	6,978	
20	14	141	2,772	2,266	3,176	
21	15	123	3,620	1,749	3,931	
22	0	0	0	0	0	-
23	0	0	0	0	0	
24	0	0	0	0	0	
25	0	0	0	0	0	
26	0	0	0	0	0	
27	0	0	0	0	0	
28	0	0	0	0	0	
29	0	0	0	0	0	
30	0	0	0	0	0	
31	0	0	0	0	0	
32	0	0	0	0	0	
33	0	0	0	0	0	
34	0	0	0	0	0	
35	0	0	0	0	0	
36	0	0	0	0	0	
37	0	0	0	0	0	
38	0	0	0	0	0	
39	0	0	0	0	0	
40	0	0	0	0	0	
41	0	0	0	0	0	
42	0	0	0	0	0	-
43	0	0	0	0	0	
44	0	0	0	0	0	
45	0	0	0	0	0	
46	0	0	0	0	0	
47	0	0	0	0	0	
48	0	0	0	0	0	
49	0	0	0	0	0	
50	0	0	0	0	0	
51	0	0	0	0	0	
52	0	0	0	0	0	

```
53 |         0           0           0           0           0 ||
54 |         0           0           0           0           0 ||
55 |         0           0           0           0           0 ||
56 |         0           0           0           0           0 ||
57                                                             ||
58                   2,746      57,926      97,622      75,297 ||
59                                                             ||
60      Risk   Acre Feet  Oil Recovery Gas Recovery Oil Fraction||
61        0     197,672          0.3          0.9        0.7693 ||
62              Avg. Thickness                                  ||-
63                        72                                    ||
```

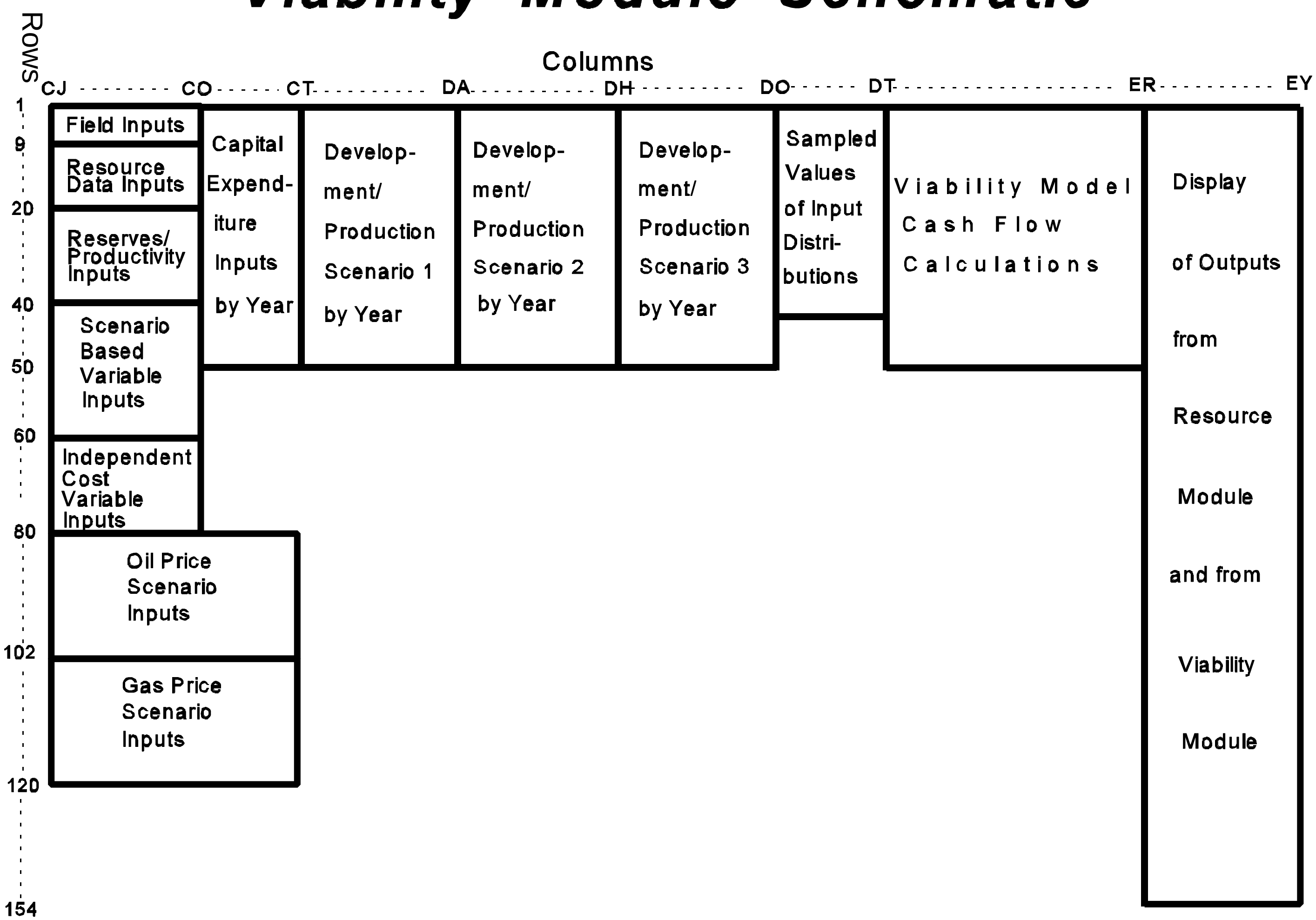
IV. <u>Viability Module</u>

A. **Objective:** Calculate the *prospective* net present value (PNPV) of the field. The PNPV is defined as the before-tax net present value for the field, excluding Federal royalties and sunk costs. A positively valued PNPV is evidence that the field can be profitable at the target discount rate while not paying Federal royalties.

B. **Inputs:** The figure, *Viability Module Schematic*, on page 33 is a map of the module which shows where to find the input, computation, and output spreadsheet cell locations. The figures on pages 51 - 65 are reproductions of the actual screen displays during an example program simulation. The figures illustrate the configuration, inputs, and results of this module.

1. *Current Year*. [spreadsheet cell CM5]
2. *Discount Rate*. [spreadsheet cells CM7]
    a. Must be from the permissible range specified by the MMS.
    b. The applicant chooses discount rate to employ in the simulation from the range of rates allowed by the MMS.
3. Resource Module Inputs in spreadsheet cells F7 .. BA56 must be identically the same to those of separate Resource Module simulation.
4. As mentioned in section III,D,1,c above, the following statistics from the *P - Total BOE* distribution [from III,C,2,b,(16) above] and the *S - Oil Frac. 1* distribution [from III,C,2,b,(17) above] are required as inputs to the Viability Module in spreadsheet cells CL13 .. CN19.
    a. *Mean*.
    b. *Standard Deviation*.
    c. *Minimum Value*.
    d. *Maximum Value*.

Viability Module Schematic



5. Minimum and maximum resource values for Scenario 2. [spreadsheet cells CL26 and CL28]
    a. These inputs establish the boundaries between the three input cost/ production scenarios.
    b. The values must be expressed in MBOE and are bounded by the minimum and maximum resource values for the field from IV,B,4,c and d above.
    c. The purpose of these inputs is to direct the program to the correct input scenarios during the simulation. If the resources sampled for the iteration are less than the *Minimum Resources for Scenario 2* then scenario 1 costs, production, etc. will be used. If resources sampled are greater than the *Maximum Resources for Scenario 2* then scenario 3 will be used. Should the sampled resources fall in between, scenario 2 will prevail.
6. Range of designed oil production capacity. [spreadsheet cells CM37 and CN37]
    a. Characterized by minimum and maximum values of Mbbl/Year.
    b. Establishes the boundaries for the design of oil production and transportation facilities when oil is the dominant product.
    c. If oil is not the dominant project, oil production capacity is unbounded.
7. Range of designed gas production capacity. [spreadsheet cells CM39 and CN39]
    a. Characterized by minimum and maximum values of MMcf/Year.
    b. Establishes the boundaries for the design of gas production and transportation facilities when gas is the dominant product.
    c. If gas is not the dominant project, gas production capacity is unbounded.

8. *Scenario Dependent Inputs*:

   a. *Platform Operating Cost* in M$/year for each scenario. This category is for all annual costs that do not vary with the rate of production (e.g., facility operation and maintenance costs). [spreadsheet cells CL48 ... CN48]

   b. *Variable Operating Cost* in $/BOE for each scenario. These are costs that do vary with the rate of production. [spreadsheet cells CL50 ... CN50]

   c. *Abandonment Cost* in M$ for each scenario. [spreadsheet cells CL52 ... CN52]

9. *Independent Cost Variable Inputs* - cost variable distributions that are independent of specific scenarios. The input parameters are characterized by minimum, likely, and maximum values of triangular distributions:

   a. *Subsea Drilling* (M$/well) - the range of the cost of drilling the average subsea well in the development project. [spreadsheet cells CL68 ... CN68]

   b. *Subsea Completion* (M$/Well) - the range of the cost of completing the average subsea well in the development project. [spreadsheet cells CL70 ... CN70]

   c. *Platform Drilling* (M$/well) - the range of the cost of drilling the average platform well in the development project. [spreadsheet cells CL72 ... CN72]

   d. *Platform Completion* (M$/Well) - the range of the cost of completing the average platform well in the development project. [spreadsheet cells CL74 ... CN74].

e. *Oil Transportation Cost* ($/bbl) - the range of the cost of transporting produced oil to the point of first sale. [spreadsheet cells CL76 ... CN76]

f. *Gas Transportation Cost* ($/mcf) - the range of the cost of transporting and processing produced gas until the point of first sale. [spreadsheet cells CL78 ... CN78]

10. Oil/Gas Real Prices (all oil and gas price and product quality adjustment parameters are supplied by the MMS). [spreadsheet cells CJ82 ... CS120]

    a. Initial oil and gas prices.

        (1) Triangularly distributed, characterized by minimum, likely, and maximum values (specified by MMS).

        (2) Both oil and gas are landed prices.

        (3) Units are in $/bbl and $/mcf.

    b. Three oil and gas real price growth segments.

        (1) Specific years when growth rates change.

        (2) Growth rates are triangularly distributed, characterized by minimum, likely, and maximum values.

        (3) Units are percent per year.

    c. Dependencies and product quality adjustment parameters will be specified by the MMS.

11. *Oil Gravity* (degrees API) - the range of expected average crude quality for the production from the field. [spreadsheet cells CL93 ... CN93]

12. *Gas Quality* (BTU/mcf) - the range of expected average hydrocarbon content from the gas production from the field. [spreadsheet cells CL93 ... CN93]

13. Capital expenditure input profiles. [spreadsheet cells CP7 ... CS46]

    a. Schedules of annual expenditures in thousands of dollars (M$).

b. Each schedule represents 1 of 3 scenarios corresponding to the low, mid, or high ranges of resources identified in IV,B,5 above.

14. Capital expenditure profiles confidence limits. [spreadsheet cells CQ2 ... CS3]

a. Characterized by + and - percentages of possible deviations.

b. Each capital expenditure profile has its own specific confidence limits.

15. Scenario Specific Activity/Production Scheduling Inputs (Each schedule represents 1 of 3 scenarios corresponding to the low, mid, or high ranges of resources identified in IV,B,5 above. Three scenarios are required): [cells CT1 ... DO50]

a. Subsea well and platform well drilling schedule.

(1) Year in which each well is drilled.

(2) One year for each well.

b. Subsea well and platform well completion schedule.

(1) Year in which each well is completed.

(2) One year for each well.

(3) Subsea well completions that do not immediately follow drilling may be more costly because they require finding and re-entering an existing hole. Higher costs for delayed completions can be input with the distribution of costs for immediate completion [cells CL 70 ... CN70] by entering more completions in columns CW, DD, and DK (i.e., 1.5 rather than 1 completion per well).

c. Production profile. [columns CZ, DG, DN]

(1) Annual schedule of production.

(2) Units are in MBOE per year.

C. **Calculations:** [spreadsheet cells DO1 ... ER50]

1. Sampling process on each iteration:

   a. The program uses a 2-stage sampling of resources/reserves to simulate sequential decisions:

      (1) Stage 1 - Resource Module calculates field **<u>resource</u>** estimate characterized by BOE volume and percent oil.

         (a) Resource estimate represents volume of recoverable hydrocarbons thought to exist at time of application.

         (b) The model uses the resource estimate to choose a capital expenditure profile scenario.

         (c) The model also uses the resource estimate and percent oil estimate to predict the dominant product (oil or gas) and design the dominant product production capacity.

      (2) Stage 2 - field **<u>reserves</u>** estimate characterized by BOE volume and percent oil.

         (a) Reserves estimate represents the total production expected when major development expenditures are committed.

         (b) Calculated using the BOE and percent oil results of the resource module calculation in (1) above in conjunction with the results of the mean, standard deviation, minimum value, maximum value measures of "Total BOE's for all Reservoirs" and "Oil Fraction for all Reservoirs" saved after initial running of the resource module and found under III,C,2,b,(16) and (17) above.

(c) The reserves estimate measures of BOE and percent oil are calculated by a random sample of truncated normal distributions. The iteration's reserves distributions are truncated at the minimum and maximum values of the resource distribution (from IV,B,4,c and d).

(d) The reserves distributions are characterized by the iteration's resource estimate as the mean value (X_i) and by a standard deviation (s) derived from a fraction of the coefficient of variation (S/U) of the resource distributions III,C,2,b,(16) & (17).

i) The fraction for the BOE sampling is one-half, which reflects the presumption that better information on geological conditions will be available at the investment decision point than was available at the application date.

ii) The fraction for the oil fraction sampling is also one-half, which reflects the presumption that better estimates of the mix as well as the size come out of data collected between application and investment.

iii) The model automatically calculates s from the relation $[(S/U)/2] = s/X_i$, which reduces to $s = (SX_i)/2U$.

iv) A sampling annex on the following page describes how difference distributions (resources - reserves) are used to verify/ estimate the standard deviation of the reserves distributions.

Sampling Annex

Objective: Explain the @Risk process for finding the standard deviation relevant to the two related (Resources/Reserves) distributions.

Rationale: The model logic calls for relating sequential picks by deriving a narrower distribution (Reserves) from a base distribution (Resources). The derivation process requires creating three distributions -- Resources, Reserves, and the difference between them. The difference distribution provides the estimate of the standard deviation for the narrowed distributions.

First distribution (Resources)

- U = mean of Resources distribution implied by detailed inputs,
- X_i = ith pick in 1st and 2nd round sampling,
- N = number of trials in 1st and 2nd round sampling.
- S = 1st round sample standard deviation of Resources distribution implied by detailed inputs. Computed in 1st round, input on 2nd round to establish narrower (one-half S) distribution for Reserves pick.
- S^2 = sum $(U - X_i)^2/N$

Second distribution (Reserves)

- X_i = mean of the ith (narrowed) distribution of reserves from which the 2nd pick on the ith trial in the 2nd round is made.
- x_i = the one pick from the ith (narrowed) distribution in 2nd round sampling,
- s = standard deviation of the single pick on the ith trial from the mean of the specific narrowed Reserves distribution used on that trial. The size of s varies with the mean (X_i) from trial to trial.
- s^2 = sum $(X_i - x_i)^2/N$ ~= $(S/2)^2$ by assumption

@ Risk Second distribution

- U = mean of Resources distribution implied by detailed inputs,
- x_i = ith pick in 2nd round sampling from the Reserves distribution,
- \$ = standard deviation of the single pick on the ith trial from the mean of the Resources distribution used on all trials.
- $\$^2$ = sum $(U - x_i)^2/N$ ~= S^2

Difference distribution

- D = mean of the difference distribution between 1st and 2nd pick from the Resources/Reserves distribution ~= 0
- d = standard deviation of this difference distribution (deviation of the 2nd pick (x_i) from the 1st pick (X_i) on each trial).
- d^2 = sum $(0 - [X_i - x_i])^2/N$ = s^2 ~= $(S/2)^2$

(e) The model uses the reserves estimate to choose a development/production scenario.

(f) The model also uses the reserves estimate and re-sampled percent oil estimate to establish the potential recovery of oil and gas and the production profile of those products.

b. Remaining uncertain cost input variables are sampled from their triangular distributions independently of resource estimates, reserves estimates, capital expenditure scenarios, or development/production scenarios.

c. Uncertain price input variables (e.g., under IV,B,10, 11, and 12 above) are also sampled from their triangular distributions independently of resource estimates, reserves estimates, capital expenditure scenarios, or development/production scenarios.

2. Calculations of Each Iteration. The figure, *Illustration of Trial Cash Flow Calculation* on the next 3 pages offers a simplified trial cash flow calculation example:

a. Production [Part 1, columns A through F]:

(1) One of 3 production profile scenarios is selected based on the size of the reserves estimate. [column B]

(2) Production profile is converted to a profile of percent-of-reserves produced in each year.

(3) Trial producibility profile is calculated by multiplying trial reserves each year by the profile of percent-of-reserves produced in each year. [Part 1 pick assumption a. and column C]

(4) Dominant product portion of trial producibility profile compared with sampled dominant product production capacity in each year to check for productivity in excess of

capacity. [column C compared to column D, resulting in column E]

ILLUSTRATION OF TRIAL CASH FLOW CALCULATION

1. <u>Gross Revenue Determination:</u>

Combines capacity pick, reserve & production profile pick, and price pick.

Assume:

a. Reserve Pick = *30* barrels

b. Price Pick = *$20* per barrel

c. Production Profile Pick as in column B, and Capacity Pick as in column D.

A	B	C	D	E	F	G
Year	Production Profile Pick (bbl)	Adjustment to Reserve Pick (bbl)	Capacity Pick (bbl)	Excess Production (bbl)	Final Profile (bbl)	Potential Gross Revenue ($)
....	0					0
1998	3	6	9	0	6	$120
1999	5	10	9	1	9	$180
2000	4	8	9	0	9	$180
2001	2	4	9	0	4	$80
2002	1	2	9	0	2	$40
....						
Totals	15	30			30	$600

ILLUSTRATION OF TRIAL CASH FLOW CALCULATION (continued)

1. <u>Operating Margin Calculation:</u>

Look at year 2000 as an example.

Assume:

a. Platform Operating Cost Pick = *$35* per year

b. Variable Operating Cost Pick = *$1* per barrel

c. Transportation Cost Pick = *$2* per barrel

Gross Revenue	9 x $20	=	$180
Transportation Cost	9 x $2	=	$18
			====
Royalty Revenue			$162
One-Sixth Royalty	$162 x (1/6)	=	$27
Royalty Revenue			$162
Platform Operating Cost Pick			$35
Variable Operating Cost	9 x $1	=	$9
			====
Operating Margin (revenue less avoidable cost)			$118

ILLUSTRATION OF TRIAL CASH FLOW CALCULATION (continued)

3. Economic Limit Cash Flow:

Production stops when variable costs exceed revenues (operating margin < 0), if this occurs every year (i.e., with $15 variable cost), then iteration is eliminated.

Assume:

a. Base Year = 1996

b. Discount Rate = *l0* percent

c. Abandonment Cost Pick = *$25*

A	H	I	J	K	L	M
Year	Operating Margin	Actual Gross Revenue	Capital, Well, and Abandonment Expenditures	Cash Flow	Discounted Cash Flow	Cash Flow at $15/bbl Operating Cost
....		0	$160	($160)	($152.6)	
1998	$67	$120	$90	($23)	($19.0)	$0
1999	$118	$180	$0	$118	$88.7	$0
2000	$118	$180	$0	$118	$80.6	$0
2001	$33	$80	$0	$33	$20.5	$0
2002	($1)	$0	$25	($25)	($14.1)	$0
....						
Totals		$560		$61	$4.1	$0

(5) Excess production of both products in years where productivity of dominant product exceeds capacity is deferred to years where capacity will not be exceeded resulting in the final BOE profile for the trial. [column F]

(6) The final oil profile is determined by applying the reserves oil fraction to each year of the final BOE profile.

(7) The final gas profile is determined by subtracting each year of the final oil profile from each year of the final BOE profile and multiplying by the mcf/BOE conversion factor (5.62).

b. Oil and Gas Price Profiles. [Part 1, pick assumption b.]

(1) Oil price profile determined by sampling starting oil price, adjusting with sampled oil quality adjuster, and ramping with sampled oil price growth rate parameters.

(2) Gas price profile determined by sampling starting gas price, adjusting with sampled gas quality adjuster, and ramping with sampled gas price growth rate parameters.

c. Gross Revenues (Part 1, column G):

(1) Potential gross revenues from oil, each year of the final oil profile multiplied by the oil price for that year.

(2) Potential gross revenues from gas, each year of the final gas profile multiplied by the gas price for that year.

(3) Total gross revenues profile is the sum of each year of the oil gross revenue profile with each year of the gas gross revenue profile.

d. Expenses:

(1) Capital-type expenses: [summarized in Part 3, column J]

(a) Capital costs are determined using the resource estimate sampled for the trial.

i) Depending on the value of resources sampled, one of three possible capital cost profiles are used.

ii) The capital cost profile is further adjusted based on a uniform sampling of the capital cost confidence limits.

(b) Well costs are determined using the reserves estimate sampled for the trial.

i) Depending on the value of reserves sampled, one of 3 possible scenarios of drilling and completion schedules for subsea and platform wells will be employed.

ii) The drilling and completion events from this schedule get multiplied by their respective costs and combined with one another to result in the profile of well costs.

(c) Abandonment expense is determined using the resource estimate sampled for the trial.

i) Depending on the value of resources sampled, one of 3 possible abandonment costs will be used for the trial.

ii) Abandonment is assumed to occur in the year immediately following the cessation of production.

(2) Operating-type expenses: [Part 2 pick assumptions a. - c.]

(a) Platform operating expenses are sampled from the input distribution and are the same for each year of production.

(b) Variable operating expenses are determined by multiplying each year of the final BOE profile by the trial's sampled value from the variable operating cost input distribution.

(c) Transportation expenses are determined by multiplying each year of the final oil and final gas by the trial's sampled values from respective transportation cost distributions and adding the results in each year.

e. Operating Margin [Part 2 calculation]:

(1) The operating margin calculation is used to find the economic limit, the last year production contributes more to revenue than cost.

(2) The operating margin is defined as potential gross revenues less operating-type expenses (platform operating expenses, variable operating expenses, and transportation expenses).

f. Economic limit calculation [Part 3, columns H through L]:

(1) The economic limit is determined through a prospective look at the operating margin for each year of operations.

(2) The economic limit is reached in the last year with a positive operating margin [e.g., column H, year 2001 in the illustration].

(3) Production and operating expenses are curtailed after that year and the field is abandoned in the following year.

(4) There is the potential for every year to have an operating loss. If and when this unlikely event occurs [e.g., column M], this trial is eliminated from the simulation.

g. Cash Flow [Part 3, columns K and L]:

(1) The cash flow is determined for each year of operations (following economic limit determination) by calculating each year's operating margin (gross revenue less operating/transport costs) and subtracting each year's capital cost from that amount. [in the example it is column H minus column J except after the economic limit year, 2001, when it is column I minus column J)

(2) The discounted cash flow is computed by discounting each year of the cash flow profile using the specified discount rate.

(3) The sum of the discounted cash flow profile is the net present value of the trial.

3. Calculations for each simulation:

a. Repeat computations over 1000 trials to result in distributions of the relevant parameters.

b. Display the following non-distributed parameters of the simulation:

(1) Field Name

(2) Water Depth

(3) Date of Application

(4) Company Applying

(5) Applicant Contact

c. Save and display outputs of the simulation mean, standard deviation, minimum, median and maximum values for the following distributions: [spreadsheet cells ER1 ... EY154]

(1) Resources

(2) Resources Oil Fraction

(3) Reserves or Resource/Reserves Difference

(4) Reserves Oil Fraction or Resource Oil Fraction/Reserves Oil Fraction Difference

(5) Platform & Well Capital Cost

(6) Operating & Transportation Cost

(7) Abandonment Cost

(8) Starting Oil Price

(9) Starting Gas Price

(10) Average Oil Price Growth

(11) Average Gas Price Growth

(12) Prospective Net Present Value (PNPV)

D. **Procedure:** After data input, a model run involves the following steps;

1. Calculate the spreadsheet [key F9], then invoke @RISK [probably Alt and F8], set the number of Iterations (1000), then Execute.
2. Note, a seed value for the random number generator is specified. The MMS specified seed value must be used so the same simulation can be reproduced.
3. To use the output format provided in RSVP, the specific outputs listed in the table on the last page of this text must be selected. If your copy of RSVP does not already list these, specify them with the @RISK Outputs, Select command.
4. When the run is complete, invoke RISKGraph [Results, Current] and inspect results.

5. Create a specific Statistics report as follows;
   a. Use commands Reports, Statistics, Format to list available statistics,
   b. Toggle off everything but;
      (1) Expected value,
      (2) Minimum value,
      (3) Maximum value,
      (4) Standard deviation,
      (5) Simulation.
      (6) Median (50 percentile) value.
   c. Touch Escape to exit and Update to save this report format.
6. Export the Statistics for the result to the spreadsheet as follows;
   a. Save a Statistics report with the @RISK commands [Reports, Statistics, All] and give the .RST a filename.
   b. Exit @RISKGraph (saving a .REV file is optional) and move to cell GA1 in the RSVP spreadsheet.
   c. Invoke @RISK [Alt and F8] and import the .RST file with the command [Results, Report] and the filename assigned in a. above.
   d. Recalculate the spreadsheet [F9] and move to the output section of the RSVP spreadsheet cell ER1. The tables on pages 63 and 64 illustrate the output format with the example output results.

V. MMS Support Contacts:

A. For technical support, problems, or questions concerning how to operate the program and on how the program works contact:

Tom Farndon	(703) 787-1502
Sam Fraser	(703) 787-1531

B. For support concerning data inputs and analysis for a specific field or project contact:

Al Durr	(504) 736-2659
Kevin Karl	(504) 736-2632

```
   CJ              CK                  CL        CM        CN    CO
 1 ||        * * *   V I A B I L I T Y   M O D U L E  * * *       |
 2 ||                                                             |
 3 ||------------------------ Field Inputs -----------------------|
 4 ||                                                             |
 5 ||                Current Year:                 1996           |
 6 ||                                                             |
 7 ||               Discount Rate (fraction):     13.00%          |
 8 ||                                                             |
 9 ||--------------------- Resource Data Inputs ------------------|
10 ||Note: Inputs obtained from separate run of resource module.  |
11 ||                                BOE           Oil Fraction|
12 ||                              --------        ------------|
13 ||         Mean (MBOE):           60,558              0.7216 |
14 ||                                                             |
15 ||   Standard Deviation (MBOE):     18,715              0.0699 |
16 ||                                                             |
17 ||      Minimum Value (MBOE):       13,785              0.3697 |
18 ||                                                             |
19 ||      Maximum Value (MBOE):      161,507              0.8604 |
20 ||                                                             |
21 ||                                                             |
22 ||------------------- Reserves/Productivity Inputs ------------|
23 ||                                                             |
24 || Min. Resources for Scenario 1:   13,785 < NOT AN INPUT!      |
25 ||                                                             |
26 || Min. Resources for Scenario 2:  105,331 MBOE                |
27 ||                                                             |
28 || Max. Resources for Scenario 2:  140,441 MBOE                |
29 ||                                                             |
30 || Max. Resources for Scenario 3:  161,507 < NOT AN INPUT!      |
31 ||                                                             |
32 || Note: Input values of Min. and Max. Resources for Scenario 2|
33 || must lie between Min. for Scenario 1 and Max. for Scenario 3|
34 ||                                                             |
35 ||                                          Minimum  Maximum |
36 ||                                          -----------------|
37 || Oil Productive Capacity (Mbbl/Year):        10,000   15,000 |
38 ||                                                             |
39 || Gas Productive Capacity (MMcf/Year):        11,000   15,000 |
40 ||                                                             |
```

```
   CJ               CK                   CL        CM        CN    CO
42 ||------------------ Scenario Based Variable Inputs -----------|
43 ||                                                             |
44 ||                                                             |
45 ||                               Scenario  Scenario  Scenario |
46 ||    Scenario Dependent Inputs       1         2         3    |
47 || -----------------------------------------------------------|
48 || Platform Operating Cost (M$/Yr)   4,960      6,400    7,561 |
49 ||                                                             |
50 || Variable Operating Cost ($/BOE)    0.60       0.50     0.40 |
51 ||                                                             |
52 ||     Abandonment Cost (M$):        8,000     10,000   12,000 |
53 ||                                                             |
54 ||                                                             |
55 ||                                                             |
56 ||                                                             |
57 ||                                                             |
58 ||                                                             |
59 ||                                                             |
60 ||                                                             |
61 ||                                                             |
62 ||----------------- Independent Cost Variable Inputs ----------|
63 ||                                                             |
64 ||                                                             |
65 ||                                                             |
66 ||  Triangularly Distributed Input Minimum Most Likely Maximum |
67 ||  ------------------------------   -------------------------|
68 ||   Subsea Drilling (M$/Well):      7,330      7,800    8,320 |
69 ||                                                             |
70 ||  Subsea Completion (M$/Well):     5,200      5,700    6,200 |
71 ||                                                             |
72 ||  Platform Drilling (M$/Well):     5,870      6,250    6,660 |
73 ||                                                             |
74 || Platform Completion (M$/Well):    1,040      1,140    1,240 |
75 ||                                                             |
76 || Oil Transportation Cost ($/bbl)    3.50       3.75     4.00 |
77 ||                                                             |
78 || Gas Transportation Cost ($/Mcf)    0.08       0.10     0.12 |
79 ||                                                             |
```

```
    CJ              CK                  CL          CM         CN     CO            CP                 CQ            CR            CS      CT
 81 ||                                                                 |
 82 ||--------------------- Oil Price Scenario Inputs --------------------|
 83 ||                                                                 |
 84 ||                                                                 |
 85 ||    Year for Real Oil Price Growth Rate 2:         2006             |
 86 ||                                                                 |-------------------------------------------------------------------|
 87 ||    Year for Real Oil Price Growth Rate 3:         2020             |       Independent          (>=-1,<=1)       Crude Quality          |
 88 ||                                                                 |       or Dependent         Rank Order    Price Adjustment Table   |
 89 ||                                   Minimum  Most Likely   Maximum |      Variable Name       Coefficient   API Gravity  Price Adjstmnt|
 90 ||                                   ------------------------------- |      ------------        ------------  ------------  ------------ |
 91 ||    Initial Oil Price ($/bbl):       16.30        17.14     18.73  |         OIPRICE                               65       ($2.13)|
 92 ||                                                                 |                                               45        $0.87 |
 93 ||    Oil Gravity (degrees API):       29.5         30.2      30.9   |                                               41        $0.87 |
 94 ||                                                                 |                                               35        $0.75 |
 95 ||  Real Oil Price Growth Rate 1:       0.00%        3.00%     5.50% |         OIPRICE                   1           30        $0.00 |
 96 ||                                                                 |                                                0       ($4.50)|
 97 ||  Real Oil Price Growth Rate 2:       0.00%        1.00%     1.50% |          RIOP2                                               |
 98 ||                                                                 |                                                             |
 99 ||  Real Oil Price Growth Rate 3:       0.00%        1.00%     1.50% |          RIOP2                    1                          |
100 ||                                                                 |-------------------------------------------------------------------|
101 ||                                                                 |
102 ||--------------------- Gas Price Scenario Inputs --------------------|
103 ||                                                                 |
104 ||                                                                 |
105 ||    Year for Real Gas Price Growth Rate 2:         2006             |
106 ||                                                                 |-------------------------------------------------------------------|
107 ||    Year for Real Gas Price Growth Rate 3:         2020             |       Independent          (>=-1,<=1)   Gas Quality   Gas Quality  |
108 ||                                                                 |       or Dependent         Rank Order     Standard   Adjust. Factor|
109 ||                                   Minimum  Most Likely   Maximum |      Variable Name       Coefficient    (BTU/mcf)     (BTU/$.01)  |
110 ||                                   ------------------------------- |      ------------        ------------  ------------  ------------ |
111 ||    Initial Gas Price ($/mcf):        1.43         1.65      2.04  |         OIPRICE                   1                                |
112 ||                                                                 |                                                             |
113 ||      Gas Quality (BTU/mcf):           900        1,000     1,100  |                                             1,028          6.5 |
114 ||                                                                 |                                                             |
115 ||  Real Gas Price Growth Rate 1:       1.00%        3.00%     4.00% |         OIPRICE                  -1                          |
116 ||                                                                 |                                                             |
117 ||  Real Gas Price Growth Rate 2:       2.00%        2.50%     3.00% |          RIOP2                    1                          |
118 ||                                                                 |                                                             |
119 ||  Real Gas Price Growth Rate 3:       2.00%        2.50%     3.00% |          RIOP2                    1                          |
120 ||                                                                 |-------------------------------------------------------------------|
```

CO	CP	CQ	CR	CS	CT

Capital Expenditure Inputs

Upper Confidence Limit:	3.00%	6.00%	10.00%
Lower Confidence Limit:	-2.00%	-5.00%	-7.00%

Year	Scenario 1 (M$)	Scenario 2 (M$)	Scenario 3 (M$)
1996	0	0	0
1997	0	0	0
1998	68,250	72,477	76,703
1999	68,250	72,477	76,703
2000	68,250	72,477	76,703
2001	0	0	0
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0
2030	0	0	0
2031	0	0	0
2032	0	0	0
2033	0	0	0
2034	0	0	0
2035	0	0	0

CT	CU	CV	CW	CX	CY	CZ	DA

Inputs for Development/Production Scenario 1

* Subsea *	* Platform *	
* Well Schedule *	* Well Schedule *	Production

Year	Drill	Complete	Drill	Complete	(MBOE/Year)
1996					
1997					
1998					
1999	8				
2000		8			4,860
2001			7		8,991
2002				7	12,501
2003					12,789
2004					10,863
2005					9,234
2006					7,848
2007					5,670
2008					4,095
2009					1,476
2010					450
2011					
2012					
2013					
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					

Inputs for Development/Production Scenario 2

Year	Subsea Well Schedule Drill	Subsea Well Schedule Complete	Platform Well Schedule Drill	Platform Well Schedule Complete	Production (MBOE/Year)
1996					
1997					
1998					
1999	10				
2000		10			6,374
2001			10		12,397
2002				10	15,497
2003					17,563
2004					14,463
2005					12,397
2006					10,331
2007					7,232
2008					5,166
2009					1,033
2010					620
2011					238
2012					
2013					
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					

Inputs for Development/Production Scenario 3

	* Subsea * * Well Schedule *	* Platform * * Well Schedule *	Production

Year	Drill	Complete	Drill	Complete	(MBOE/Year)
1996					
1997					
1998					
1999	12				
2000		12			7,684
2001			11		14,946
2002				11	19,928
2003					22,419
2004					17,437
2005					12,455
2006					8,719
2007					7,473
2008					6,474
2009					3,737
2010					1,868
2011					1,246
2012					165
2013					
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					

---------- Sampled Values of Input Distributions for Trial --------

Variable	Units	Name	Value
BOE Resources	MBOE	\RESOURCES	75,297
Resources Oil Fraction	Fraction	\GOR	0.769
Minimum Oil Fraction for Oil	Fraction		0.500
Gas to BOE Conversion Factor	Mcf/bbl		5.62
Oil Production Capacity	Mbbl/Year	\OCAP	15,705

Row	Description	Units	Name	Value
10	Gas Production Capacity	MBOE/Year	\GCAP	2,929
11	BOE Reserves	MBOE	\RESERVES	75,297
12	Resource/Reserves Difference	MBOE		(0)
13	Reserves Oil Fraction	Fraction	\RGOR	0.769
14	Oil Fraction Difference	Fraction		0.001
15	CAPEX Confidence Factor		\CAPCON	1.005
16	Subsea Drilling Cost	M$/Well	\SUBDRIL	7,817
17	Subsea Completion Cost	M$/Well	\SUBCOMP	5,700
18	Platform Drilling Cost	M$/Well	\PLATDRIL	6,260
19	Platform Completion Cost	M$/Well	\PLATCOMP	1,140
20	Platform Operating Cost	M$/Year	\PLATOPCOST	4,960
21	Variable Operating Cost	$/BOE	\VAROPCOST	0.60
22	Oil Transportation Cost	$/bbl	\OTRANS	3.75
23	Oil Gravity	degrees API		30.2
24	Oil Quality Interpolation			0.000
25	Oil Quality Interpolation			0.000
26	Oil Quality Interpolation			0.000
27	Oil Quality Interpolation			0.030
28	Oil Quality Interpolation			0.000
29	Oil Quality Interpolation			0.000
30	Oil Quality Interpolation			0.000
31	Oil Quality Interpolation			0.000
32	Oil Quality Interpolation			0.000
33	Oil Quality Adjustment	$/bbl	\OQUAL	$0.030
34	Gas Transportation Cost	$/mcf	\GTRANS	0.10
35	Gas Price			$1.71
36	Gas Quality	BTU/mcf		1,000
37	Gas Quality Adjustment	$/mcf	\GQUAL	($0.046)
38	Abandonment Cost	M$	\ABANDON	8,000
39	Initial Oil Price	$/bbl	\OIPRICE	$17.42
40	Real Oil Price Growth Rate 1	%/Year+100%	\RIOP1	102.83%
41	Initial Gas Price	$/mcf	\GIPRICE	$1.66
42	Real Gas Price Growth Rate 1	%/Year+100%	\RIGP1	102.67%
43	Oil Price at \YROGRO2	$/bbl	\O2PRICE	$23.03
44	Gas Price at \YRGGRO2	$/mcf	\G2PRICE	$2.16
45	Real Oil Price Growth Rate 2	%/Year+100%	\RIOP2	100.83%
46	Real Gas Price Growth Rate 2	%/Year+100%	\RIGP2	102.50%
47	Oil Price at \YROGRO3	$/bbl	\O3PRICE	$25.87
48	Gas Price at \YRGGRO3	$/mcf	\G3PRICE	$3.05
49	Real Oil Price Growth Rate 3	%/Year+100%	\RIOP3	100.83%
50	Real Gas Price Growth Rate 3	%/Year+100%	\RIGP3	102.50%
51				
52				
53				
54				
55				
56				
57				
58				
59				
60				

Viability Module Calculations:

DT	DU	DV	DW	DX	DY
2	Production				
3		Selected	Reserves	Excess	Final
4		Scenario	Adjusted	Production	Profile
5	Year	(MBOE)	(MBOE)	(MBOE)	(MBOE)
7	1996	0	0	0	0
8	1997	0	0	0	0
9	1998	0	0	0	0
10	1999	0	0	0	0
11	2000	4,860	4,645	0	4,645
12	2001	8,991	8,594	0	8,594
13	2002	12,501	11,949	0	11,949
14	2003	12,789	12,224	0	12,224

15	||	2004	10,863	10,383	0	10,383
16	||	2005	9,234	8,826	0	8,826
17	||	2006	7,848	7,501	0	7,501
18	||	2007	5,670	5,420	0	5,420
19	||	2008	4,095	3,914	0	3,914
20	||	2009	1,476	1,411	0	1,411
21	||	2010	450	430	0	430
22	||	2011	0	0	0	0
23	||	2012	0	0	0	0
24	||	2013	0	0	0	0
25	||	2014	0	0	0	0
26	||	2015	0	0	0	0
27	||	2016	0	0	0	0
28	||	2017	0	0	0	0
29	||	2018	0	0	0	0
30	||	2019	0	0	0	0
31	||	2020	0	0	0	0
32	||	2021	0	0	0	0
33	||	2022	0	0	0	0
34	||	2023	0	0	0	0
35	||	2024	0	0	0	0
36	||	2025	0	0	0	0
37	||	2026	0	0	0	0
38	||	2027	0	0	0	0
39	||	2028	0	0	0	0
40	||	2029	0	0	0	0
41	||	2030	0	0	0	0
42	||	2031	0	0	0	0
43	||	2032	0	0	0	0
44	||	2033	0	0	0	0
45	||	2034	0	0	0	0
46	||	2035	0	0	0	0
47	||					
48	||		78,777			
49	||					
50						
51						
52						
53						
54						
55						
56						
57						
58						
59						
60						

	DZ	EA	EB	EC	ED	EE	EF
1							
2	------ Production	------	|	------------- Revenues	-------------		|
3	Oil	Gas	|	Oil	Gas	Gross	|
4	Production	Production	|	Price	Price	Revenue	|
5	(Mbbl)	(MMcf)	|	($/bbl)	($/mcf)	(M$)	|
6	-----------	-----------	|	-----------	-----------	-----------	|
7	0	0	|	17.42	1.66	0	|
8	0	0	|	17.91	1.70	0	|
9	0	0	|	18.42	1.75	0	|
10	0	0	|	18.94	1.80	0	|
11	3,570	6,042	|	19.48	1.84	80,691	|
12	6,605	11,178	|	20.03	1.89	153,473	|
13	9,183	15,542	|	20.60	1.94	219,384	|
14	9,395	15,900	|	21.18	2.00	230,746	|
15	7,980	13,506	|	21.78	2.05	201,504	|
16	6,783	11,480	|	22.40	2.10	176,101	|
17	5,765	9,757	|	23.03	2.16	153,875	|
18	4,165	7,049	|	23.23	2.21	112,351	|
19	3,008	5,091	|	23.42	2.27	82,007	|

20	1,084	1,835	23.62	2.33	29,874
21	331	559	23.81	2.38	9,206
22	0	0	24.01	2.44	0
23	0	0	24.21	2.50	0
24	0	0	24.41	2.57	0
25	0	0	24.62	2.63	0
26	0	0	24.82	2.70	0
27	0	0	25.03	2.76	0
28	0	0	25.24	2.83	0
29	0	0	25.45	2.90	0
30	0	0	25.66	2.98	0
31	0	0	25.87	3.05	0
32	0	0	26.09	3.13	0
33	0	0	26.31	3.21	0
34	0	0	26.53	3.29	0
35	0	0	26.75	3.37	0
36	0	0	26.97	3.45	0
37	0	0	27.19	3.54	0
38	0	0	27.42	3.63	0
39	0	0	27.65	3.72	0
40	0	0	27.88	3.81	0
41	0	0	28.11	3.91	0
42	0	0	28.35	4.00	0
43	0	0	28.58	4.10	0
44	0	0	28.82	4.21	0
45	0	0	29.06	4.31	0
46	0	0	29.30	4.42	0
47					
48					
49					
50					
51					
52					
53					
54					
55					
56					
57					
58					
59					
60					

	EF	EG	EH	EI	EJ	EK
1						
2		Expenses				
3				Platform	Variable	
4		Capital	Well	Operating	Operating	Transpo.
5		(M$)	(M$)	(M$)	(M$)	(M$)
6						
7		0	0	0	0	0
8		0	0	0	0	0
9		68,591	0	0	0	0
10		68,591	62,533	0	0	0
11		68,591	45,600	4,960	2,787	13,992
12		0	43,820	4,960	5,156	25,886
13		0	7,980	4,960	7,169	35,991
14		0	0	4,960	7,334	36,820
15		0	0	4,960	6,230	31,275
16		0	0	4,960	5,296	26,585
17		0	0	4,960	4,501	22,595
18		0	0	4,960	3,252	16,324
19		0	0	4,960	2,348	11,790
20		0	0	4,960	846	4,250
21		0	0	4,960	258	1,296
22		0	0	0	0	0
23		0	0	0	0	0
24		0	0	0	0	0

25	0	0	0	0	0
26	0	0	0	0	0
27	0	0	0	0	0
28	0	0	0	0	0
29	0	0	0	0	0
30	0	0	0	0	0
31	0	0	0	0	0
32	0	0	0	0	0
33	0	0	0	0	0
34	0	0	0	0	0
35	0	0	0	0	0
36	0	0	0	0	0
37	0	0	0	0	0
38	0	0	0	0	0
39	0	0	0	0	0
40	0	0	0	0	0
41	0	0	0	0	0
42	0	0	0	0	0
43	0	0	0	0	0
44	0	0	0	0	0
45	0	0	0	0	0
46	0	0	0	0	0
47					
48			29,760		
49					
50					
51					
52					
53					
54					
55					
56					
57					
58					
59					
60					

	EL	EM	EN	EO	EP	EQ	ER
1							
2	Expenses				Cash Flow		
3	Operating Margin (M$)	Operating Margin Counter	Abandonment (M$)		Cash Flow (M$)	Discounted Cash Flow (M$)	
7	0	0	0		0	0	
8	0	0	0		0	0	
9	0	0	0		(68,591)	(53,717)	
10	0	0	0		(131,125)	(90,876)	
11	58,951	1	0		(55,240)	(33,880)	
12	117,471	1	0		73,651	39,975	
13	171,263	1	0		163,283	78,428	
14	181,631	1	0		181,631	77,204	
15	159,039	1	0		159,039	59,824	
16	139,260	1	0		139,260	46,357	
17	121,819	1	0		121,819	35,886	
18	87,815	1	0		87,815	22,893	
19	62,908	1	0		62,908	14,513	
20	19,818	1	0		19,818	4,046	
21	2,692	1	0		2,692	486	
22	0	0	8,000		(8,000)	(1,279)	
23	0	0	0		0	0	
24	0	0	0		0	0	
25	0	0	0		0	0	
26	0	0	0		0	0	
27	0	0	0		0	0	
28	0	0	0		0	0	
29	0	0	0		0	0	

```
30         0        0          0 |          0           0 |
31         0        0          0 |          0           0 |
32         0        0          0 |          0           0 |
33         0        0          0 |          0           0 |
34         0        0          0 |          0           0 |
35         0        0          0 |          0           0 |
36         0        0          0 |          0           0 |
37         0        0          0 |          0           0 |
38         0        0          0 |          0           0 |
39         0        0          0 |          0           0 |
40         0        0          0 |          0           0 |
41         0        0          0 |          0           0 |
42         0        0          0 |          0           0 |
43         0        0          0 |          0           0 |
44         0        0          0 |          0           0 |
45         0        0          0 |          0           0 |
46         0        0          0 |          0           0 |
47                                                        |
48                         8,000                    199,862 |
49                                                        |
50                                                        1 |
51                                                        |
52                                                        |
53                                                        |
54                                                        |
55                                                        |
56                                                        |
57                                                        |
58                                                        |
59                                                        |
60                                                        |
   ER              ES                 ET      EU       EV       EW       EX  EY
 1 |            * * * * * * * * * * * * * * * * * * * * * * *               |
 2 |            *                                           *               |
 3 |            *           < < <   R S V P   > > >         *               |
 4 |            *                                           *               |
 5 |            * * * * * * * * * * * * * * * * * * * * * * *               |
 6 |                                                                        |
 7 |           Field Name:         Buffalo                                  |
 8 |                                                                        |
 9 |   Field Water Depth (meters):     745                                  |
10 |                                                                        |
11 |      Date of Application:     June 1, 1996                             |
12 |                                                                        |
13 |     Name of Company Applying:  Richalo Exploration Company             |
14 |                                                                        |
15 |        Applicant Contact:      Richard Winnor                          |
16 |                                                                        |
17 |     Contact Telephone Number:  (703) 787-1533                          |
18 |                                                                        |
19 |                                                                        |
20 | RESOURCE MODULE OUTPUTS FOR THE FIELD:     Date of Run: 16-Aug    1990 |
21 | ----------------------------------------                               |
22 |                                                                        |
23 |          Number of Trials in Simulation:                         1,000 |
24 |                                                                        |
25 |     Geologic Probability of Producing No Hydrocarbons:           0.000 |
26 |                                                                        |
27 |                                 Mean  Standard  Minimum Median Maximum |
28 |                                Value  Deviation  Value  Value   Value  |
29 |                               -----------------------------------------|
30 |             Acres:              2,305      523     896   2,283   4,560 |
31 |                                                                        |
32 |         Acre-Feet (000):         164.7     46.7    49.7   159.4   456.5 |
33 |                                                                        |
34 |      Oil Recovery (bbl/AF):      351.8     51.0   201.1   351.1   532.3 |
```

```
|     Gas Recovery (mcf/AF):      902.4    363.2     0.0   849.8 3,076.0 |
|                                                                       |
| FIELD RESOURCE ESTIMATES:                                             |
|       Liquids in MMbbl          Mean  Standard  Minimum Median Maximum |
|        Gasses in Bcf           Value  Deviation  Value  Value   Value  |
| ----------------------------------------------------------------------|
|    Oil from Oil Reservoirs:      35.7     14.3     0.6    35.3   104.5 |
|                                                                       |
| Associated Gas from Oil Res.:    41.5     19.1     0.4    39.9   202.8 |
|                                                                       |
|    Gas from Gas Reservoirs:      39.6     30.8     0.0    32.9   232.2 |
|                                                                       |
|   Condensate from Gas Res.:       4.3      3.3     0.0     3.7    20.6 |
|                                                                       |
| Oil from Oil & Gas Reservoirs:    3.0      4.5     0.0     1.6    47.0 |
|                                                                       |
| Associated Gas from O&G Res.:     3.9      7.6     0.0     1.6   136.2 |
|                                                                       |
| Gas from Oil & Gas Reservoirs:    8.6     12.1     0.0     4.9   111.5 |
|                                                                       |
|   Condensate from O&G Res.:       0.8      1.3     0.0     0.4    13.8 |
|                                                                       |
| Total Oil (Oil + Condensate):    43.9     14.6     6.1    42.6   112.3 |
|                                                                       |
| Total Gas (Gas + Assoc. Gas):    93.7     35.2    19.4    88.1   276.6 |
ER             ES                 ET      EU       EV      EW       EX  EY
|       RSVP Output Page 2                  Date of Run: 16-Aug    1990 |
|                                                                       |
|                                                                       |
|  VIABILTIY MODULE OUTPUTS FOR THE FIELD:                              |
| ----------------------------------------                              |
|                                                                       |
|       BOE Conversion Factor:   5.620 mcf/bbl                          |
|                                                                       |
|        Discount Rate:          13.00%                                 |
|                                                                       |
|                                 Mean  Standard  Minimum Median Maximum |
|                                Value  Deviation  Value  Value   Value  |
|                               ----------------------------------------|
| Resources:                                                            |
|                                                                       |
|       Millions of BOE:          60.56    18.71   13.79   58.59  161.51 |
|                                                                       |
|        Oil Fraction:            72.16%    6.99%  36.97%  73.29%  86.04%|
|                                                                       |
|                                                                       |
| Reserves:                                                             |
|                                                                       |
|       Millions of BOE:          60.64     9.71   14.56   57.72  159.97 |
|                                                                       |
|        Oil Fraction:            72.02%    3.39%  37.34%  72.77%  86.01%|
|                                                                       |
|                                                                       |
| Expenses:                                                             |
|                                                                       |
|    Platforms & Wells (MM$):     368.2     13.5   354.3   365.8   491.1 |
|                                                                       |
| Operating & Transpo. ($/BOE):    4.44     0.41    3.33    4.42    6.47 |
|                                                                       |
|      Abandonment (MM$):           8.0      0.3     8.0     8.0    12.0 |
|                                                                       |
|                                                                       |
| Product Prices:                                                       |
|                                                                       |
|  Starting Oil Price ($/bbl):    17.42     0.50   16.30   17.37   18.67 |
```

```
101 |                                                                            |
102 | Avg. Oil Price Growth (%/Yr.):   2.29%    0.82%   0.15%   2.29%   4.15%|
103 |                                                                            |
104 |  Starting Gas Price ($/mcf):     1.66     0.14    1.32    1.65    2.13 |
105 |                                                                            |
106 | Avg. Gas Price Growth (%/Yr.):   2.63%    0.46%   1.40%   2.66%   3.68%|
107 |                                                                            |
108 |    Prospective Net Present                                                 |
109 |   Value of the Field (MM$):    101.84   132.91 (187.58)  86.31  678.79 |
110 |                                                                            |
111 |                                                                            |
112 |                                                                            |
113 |                                                                            |
114 |                                                                            |
115 |                                                                            |
116 |                                                                            |
117 |                                                                            |
118 |                                                                            |
119 |                                                                            |
120 |                                                                            |
121 |                                                                            |
   ER              ES                  ET       EU       EV       EW       EX   EY
113 |      SAMPLING PARAMETERS                                                   |
114 | -------------------------------------------------------                    |
115 | Title:                         C:\ATRISK\RSVPEX1.WK1                       |
116 | Sampling type:                 Latin Hypercube                             |
117 | Number of simulations:         1                                           |
118 | Number of iterations:          1000                                        |
119 | Seed value:                    104                                         |
120 | Output ranges:                                                             |
121 | A - ACRES                      CF58                                        |
122 | B - ACRE FEET                  CF61                                        |
123 | C - OIL RECOVRY                CG61                                        |
124 | D - GAS RECOVRY                CH61                                        |
125 | E - RISK                       CE61                                        |
126 | F - OIL, OIL                   BO58                                        |
127 | G - OIL, GAS                   BP58                                        |
128 | H - GAS, GAS                   BS51                                        |
129 | I - GAS, OIL                   BT58                                        |
130 | J - BOTH, OIL                  BX58                                        |
131 | K - BOTH, A-GAS                BY58                                        |
132 | L - BOTH, GAS                  CB58                                        |
133 | M - BOTH, COND.                CC58                                        |
134 | N - TOTAL OIL                  CG58                                        |
135 | O - TOTAL GAS                  CH58                                        |
136 | P - TOTAL BOE                  CI58                                        |
137 | Q - RESERVES                   DS11                                        |
138 | R - R/RDIFF.                   DS12                                        |
139 | S - OIL FRAC. 1                CI61                                        |
140 | T - OIL FRAC. 2                DS13                                        |
141 | U - O FRAC DIFF                DS14                                        |
142 | XA - CAPEX                     EZ48                                        |
143 | XB - OPEX                      FB50                                        |
144 | XC - ABANDON                   EN48                                        |
145 | XD - OIL $                     DS27                                        |
146 | XE - OIL $ ^                   FC48                                        |
147 | XF - GAS $                     DS29                                        |
```

```
XG - GAS $ ^                 FD48                                      |
XH - NPV                     EQ48                                      |
ZA - FNPV                    FR48                                      |
ZB - VOLUM PNPV              FX48                                      |
ZC - TRUNCATED               FQ50                                      |
Sampling regions:            Disabled                                  |
```

VI. MMS (Proprietary) Module:

The *RSVPP* program adds the Economic Module to the *RSVP* program. It is not made available to applicants to encourage candid applications. A procedure for modifying the *RSVP* program to approximate the simulation of FNPV in the *RSVPP* program is described in Appendix A: Approximating FNPV.

RSVPP Calculations: The input ranges and distributions of possible values for each variable that affects the profitability of the field for the *RSVPP* program are precisely the same as those used in the *RSVP* to calculate the PNPV. As in the *RSVP*, one value from the input distribution of each variable is selected at random for each iteration. A discounted cash flow (DCF) value for the field is computed using this combination of samples for the iteration. This process is performed 1,000 times, each time with a set of values selected at random. A random number seed is specified so that both the *RSVP* and *RSVPP* use the same random samples. The PNPV calculated in the *RSVP* will be precisely the same as calculated in the *RSVPP*.

There are two additional input parameters needed in the *RSVPP* program to calculate the FNPV. For this calculation, Federal royalties and the after-tax (non-expensed) portion of the sunk cost (adjusted sunk cost) reported by the applicant are used in the DCF simulation. During certain simulation iterations where the sampled inputs yield a DCF value below a minimum profit threshold level, the adjusted sunk costs are substituted for the calculated DCF value. This substitution simulates the situation where a prudent operator would foresee extremely bad outcomes prior to development and would abandon in favor of developing other projects. The mean of the 1,000 iteration values, either the DCF or the substitute from each iteration, is the FNPV.

The *RSVPP* program is also used to determine the precise volume suspension needed. For this calculation, a separate DCF value is computed on each of the iterations of the PNPV/FNPV simulation. The separate computation is a DCF value excluding sunk costs from the cash flow and applying royalty only to the anticipated production above a specified volume, sort of a partial royalty PNPV, or better described as a volume suspension net present value (VNPV). The mean of the 1,000 iteration values for this separate DCF calculation is the VNPV. When PNPV is positive and FNPV is negative, the mandated minimum suspension volume for the field's water depth category is the first specified volume tested. If the VNPV using the MSV is positive, the applicant is awarded the MSV. If VNPV is negative at the MSV, the 1,000 iteration simulation is repeated with larger suspension volumes until VNPV approximates zero. Precision for the volume determination is the smallest 100,000 BOE increase in the MSV that makes VNPV > 0.

Appendix A: Approximating FNPV

An **Imitation FNPV** can be calculated with *RSVP* by making the following data input/program changes. The imitation FNPV provides a close approximation of the minimum value of FNPV. That is, the *RSVPP* program will calculate a **True FNPV** of at least the imitation FNPV calculated using the *RSVP* program. Therefore, using the given data input assumptions, an applicant knows that a field with a positively valued imitation FNPV has no chance of receiving a royalty suspension. The table on the next page illustrates the relationship of these measures from the EXAMPLE.WK1 file included on the *RSVP* program disk.

A. Add adjusted sunk costs (65% of eligible costs between discovery and submission of application) into the cash flow as an additional capital expenditure in year 1 (cell EG7). Edit the existing formula in the cell by adding the adjusted sunk cost to the end of the formula.

B. Change starting price to a net price by multiplying the MMS specified starting price (cells CL91 ... CN91 and CL111 ... CN111) by one minus the royalty rate.

C. Multiply the transportation cost (cells CL76 ... CN76 and CL78 ... CN78) by one minus the royalty rate. The reduction in transportation cost is necessary to complete the adjustment of the royalty base (the difference between price and the transportation cost), as shown in Attachment A to this appendix.

D. Rerun the program. The PNPV (mean of the output distribution *XH* - *NPV*) becomes a **Modified PNPV** (Row 2 of the illustration table).

If all reservoirs of the field were sampled as being dry together on any iteration, the modified PNPV needs to be further manipulated to become the imitation FNPV by:

E. Multiplying the dry risk (mean of the output distribution *E - RISK*) by the adjusted sunk cost, and subtracting that amount from the modified PNPV. Row 3 (*Imitation FNPV*) of the illustration table is calculated as follows:

Imitation FNPV = Modified PNPV - [Dry Risk * Sunk Cost * (1- Federal Tax Rate)]

Imitation FNPV = -30,244 - [0.067 * 74,900 * (1- 0.35)] = -33,506

Approximating FNPV with Modifications to PNPV

Measures	Example Values (000$ except 4.)
1. PNPV	51,926
2. Modified PNPV	-30,244
3. Imitation FNPV	-33,506
4. Dry trials (of a possible 1,000)	67
5. Floor FNPV	-33,422

Rows 1 through 4 above can be calculated by the applicant with the *RSVP* program, row 5 can only be calculated using the proprietary *RSVPP* program. Rows 1, 2, and 4 can be read directly from the *RSVP* model results, and row 3 is computed as described in item E above.

The imitation FNPV (Row 3 of the illustration table) closely approximates the **Floor FNPV** (Row 5 of the illustration table). The floor FNPV is produced using the *RSVPP* model without the feature which replaces excessively negative iterations with the adjusted sunk cost as described in the *RSVPP* Calculations section above. Omitting the replacement feature produces the lowest possible value for FNPV.

When some trials are too negative to support further development, the true FNPV from the *RSVPP* will be greater than the imitation FNPV from the *RSVP*. This deviation occurs as a result of sunk costs being averaged into the true FNPV calculation on certain iterations rather than averaging exceptionally large losses as is the case in the imitation FNPV calculation using the *RSVP* model. This means that the imitation FNPV is effectively a lower bound for the true FNPV. Therefore, if the imitation FNPV is positive, the field cannot qualify for royalty relief. If the imitation FNPV is negative, the field may or may not qualify.

Attachment A: Royalty Approximation with *RSVP*

The *RSVP* program does not include royalties as part of its DCF calculations. Federal royalties need to be included in the calculation of an imitation FNPV using the *RSVP*. This approximation is accomplished with modifications to the starting oil and gas prices and to the oil and gas transportation costs as described above. The logic involved in using this approximation is as follows:

Gross revenues are calculated using the following formula:

$$GR = (Q_o * P_o) + (Q_g * P_g)$$

where: GR = Gross Revenues ($)
Q_o = Oil Production (bbl)
P_o = Oil Price ($/bbl)
Q_g = Gas Production (mcf)
P_g = Gas Price ($/mcf)

Federal Royalties are routinely calculated using the following formula:

Federal Royalties = (Gross Revenue - Transportation Costs) * Royalty Rate

Expanding:

$$FR = [((Q_o * P_o) + (Q_g * P_g)) - ((Q_o * T_o) + (Q_g * T_g))] * r$$

where: FR = Federal Royalties ($)
T_o = Oil Transportation Cost ($/bbl)
T_g = Gas Transportation Cost ($/mcf)
r = Royalty Rate (fraction)

Therefore:

$$NR = [((Q_o * P_o) + (Q_g * P_g)) - ((Q_o * T_o) + (Q_g * T_g))] * (1 - r)$$

where: NR = Net Revenues (gross revenues net of both federal royalties and transportation costs)

Rearranging:

$$NR = [Q_o * ((P_o * (1 - r)) - (T_o * (1 - r))] + [Q_g * ((P_g * (1 - r)) - (T_g * (1 - r))]$$

Thus, we have a modified form of the revenue equation where prices and transportation costs are multiplied by (1 - r) to result in revenues net of royalties. Therefore, if starting oil and gas price inputs and transportation cost inputs to the *RSVP* program are exogenously adjusted by multiplying by the factor (1 - r), a suitable proxy for the internal calculation of royalties in the *RSVPP* program can be achieved.

This proxy is not precise (Rows 3 and 5 of the illustration table are not exactly equal), though the deviation is trivial. The small difference has to do with when royalties (or pseudo royalties) are considered in the cash flow decision to abandon in the respective programs. The *RSVPP* program excludes royalties in this decision. However, the royalty proxy in the *RSVP* does not see the proxy as royalties, per se, and, therefore, does not know to exclude them. The result is that the royalty proxy may cause the *RSVP* program to abandon sooner on some iterations than the *RSVPP* program does. This could lead to the calculation of a slightly higher value of imitation FNPV than the value of floor FNPV for some fields. Our tests indicate that this difference is very small, probably never great enough to misguide the decision to apply or not to apply for a royalty suspension.

Appendix B: Documentation Errata

Errata #1 for RSVP Documentation

On page 14 of the documentation, add the following new subsection III, D., 1., c. and redesignate the existing subsections c., d., and e. as d., e., and f.

c. If the entire field is sampled as being dry during one or more iterations (i.e., output distribution *E - Dry Risk* >0), @RISK filtering must be used to calculate conditional values for the two key distributions described in III, D., 1., d. below. Filtering removes values from these distributions that occur during iterations where the entire field is sampled as being dry.

(1) This adjustment removes a distortion from the Resource Module's *P - Total BOE* and *S - Oil Frac.* output distributions. The Resource Module in the initial simulation run develops distributions of resources and of oil fraction that include zero values from iterations where the field was sampled as being dry. Removing these zero values from the distributions by "filtering" results produces distributions which represent the condition when hydrocarbons are present.

(2) The @RISK procedure for filtering is as follows:

(a) From @RISKGraph (Alt and F8), invoke Zoom/Rescale, Global, Configure, Filter.

(b) Enter the filter condition ">0" and select Go.

d. Certain statistics from the *P - Total BOE* distribution ...

Older versions of the RSVP.WK1 and EXAMPLE.WK1 program spreadsheet files may require the following changes in order to implement the new subsection III, D., 1., c. Of the documentation:

Change spreadsheet cell CF58 formula
From: @IF(@SUM(CF7..CF56)=0,0.1,@SUM(CF7..CF56))
To: @SUM(CF7..CF56)

Change spreadsheet cell CF63 formula
From: +CF61/CF58
To: @IF(CF58=0,0,CF61/CF58)

Change spreadsheet cell CI58 formula
From: @IF(@SUM(CI7..CI56)=0,0.001,@SUM(CI7..CI56))
To: @SUM(CI7..CI56)

Change spreadsheet cell CI61 formula
From: +CG58/CI58
To: @IF(CI58=0,0,CG58/CI58)

Change spreadsheet cell DS11 formula
From: @TNORMAL(DS5,(CL15*DS5)/(2*CL13),CL17,CL19)
To: @IF(DS5=0,0,@TNORMAL(DS5,(CL15*DS5)/(2*CL13),CL17,CL19))

Add the shaded terms to the formula in spreadsheet cell DY8 using the LOTUS 1-2-3 edit function
@IF(DS$6>=DS$7,@IF(DX8>0,DS$9,@IF(DW8=0#AND#DX7<DS$9,DX7,DW8 +*DX7*)),
@IF(DX8>0,DS$10,@IF(DW8=0#AND#DX7<DS$10,DX7,DW8 +*DX7*)))
after editing, copy cell DY8 over the range DY8..DY46 using the LOTUS 1-2-3 copy command.

Once these changes are made to both the RSVP.WK1 and the EXAMPLE.WK1 programs, the EXAMPLE.WK1 program should be re-run. Re-running is a two-stage process. First the program should be run, the output distributions should be filtered, and the data from the *P - Total BOE* and *S - Oil Frac. 1* output distributions should be input into the program, and the program should be run again. As a check, the filtered values to be input back into the program should be:

Distribution Parameter	*P - Total BOE*	*S - Oil Frac. 1*
Mean	55,750.99	0.8665088
Standard Deviation	29,947.05	0.01138318
Minimum Value	3,039.258	0.8267283
Maximum Value	184,003.7	0.8979718

After verifying these results, inputting them into the program, and re-running the program, the mean value of the Prospective Net Present Value of the Field (also output distribution *XH - NPV*) should become $51,926.